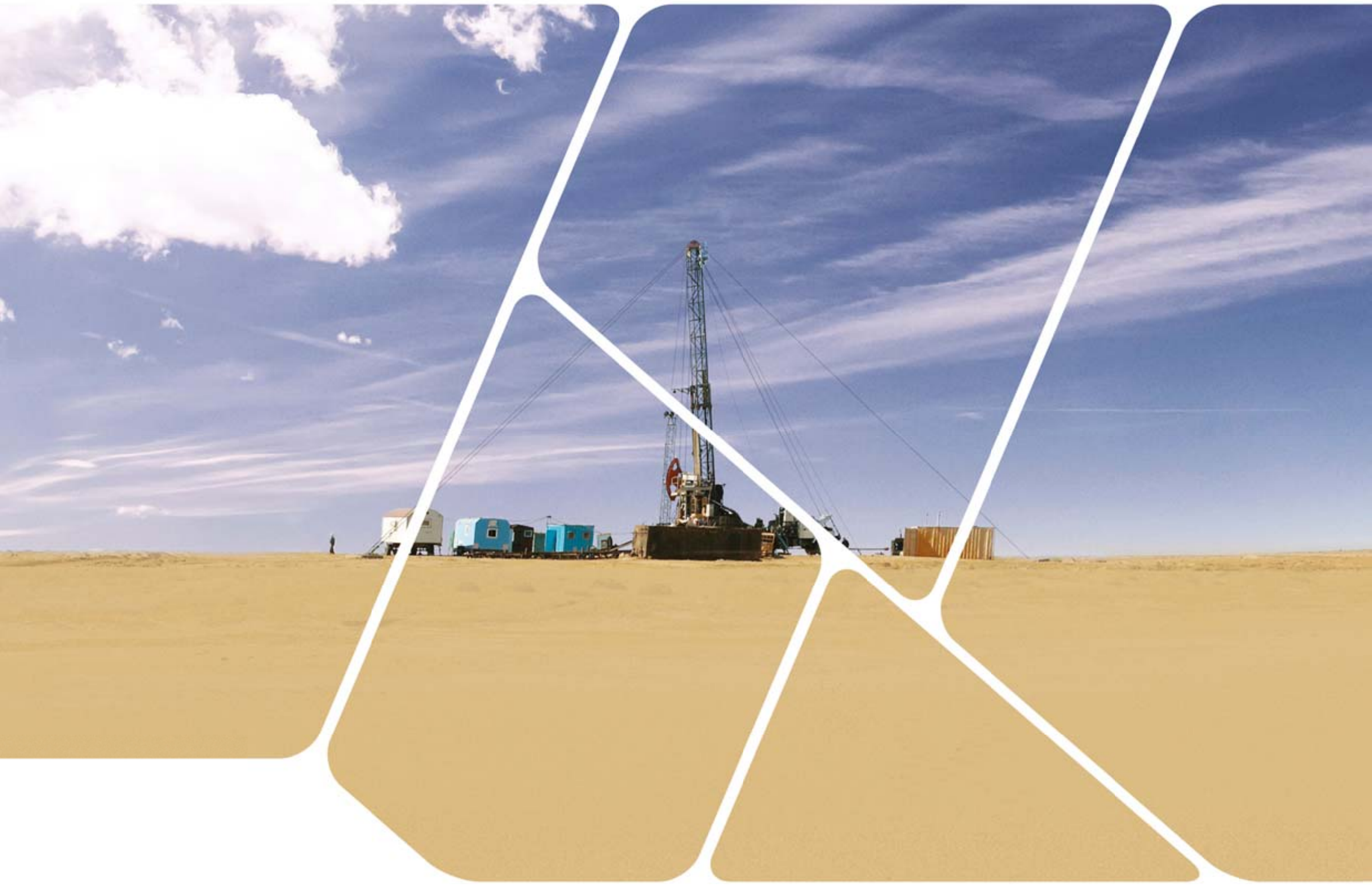

RESERVOIR ENGINEERING GRADUATE CERTIFICATE - *Week 7*

Drive Mechanisms - EOR

A special course by IFP Training for REPSOL ALGERIA
Alger –December 11 to 15, 2016

REPSOL

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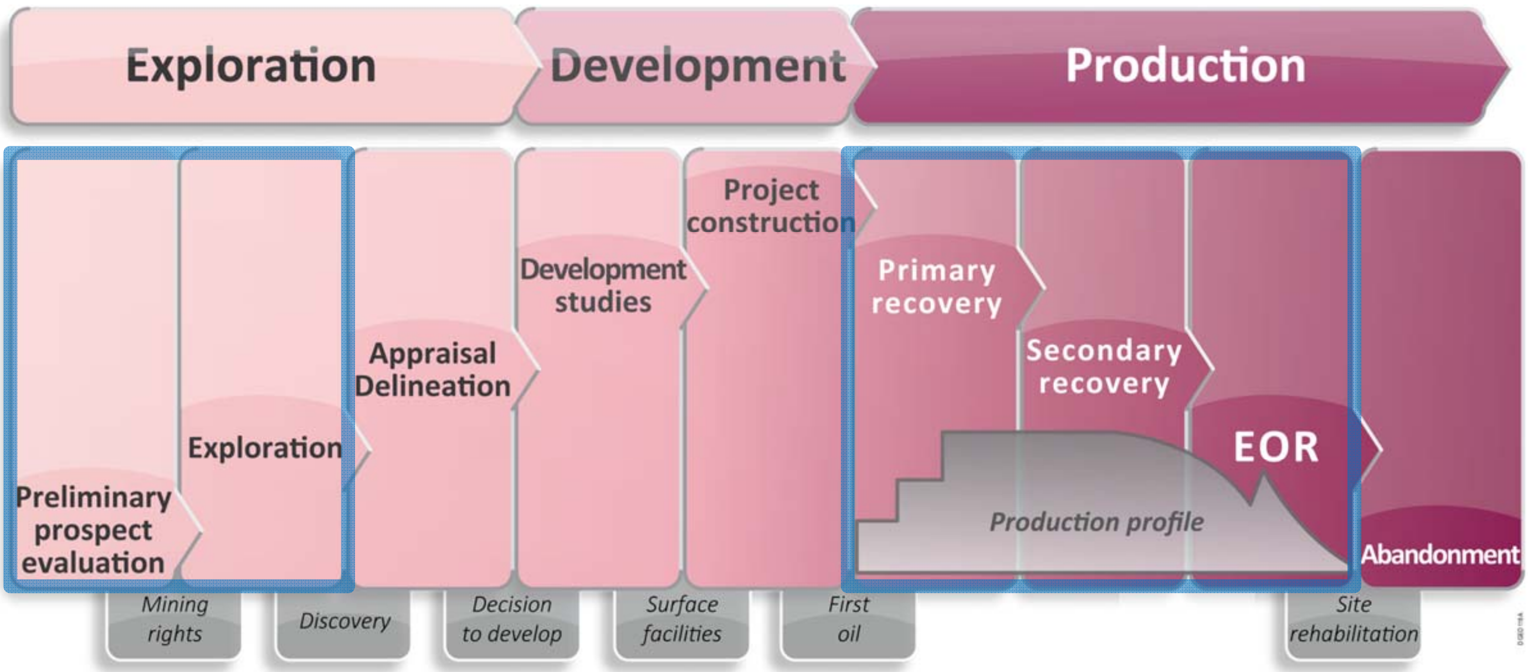
Course contents

An IFP Training Course for REPSOL

Introduction to drive mechanisms and EOR

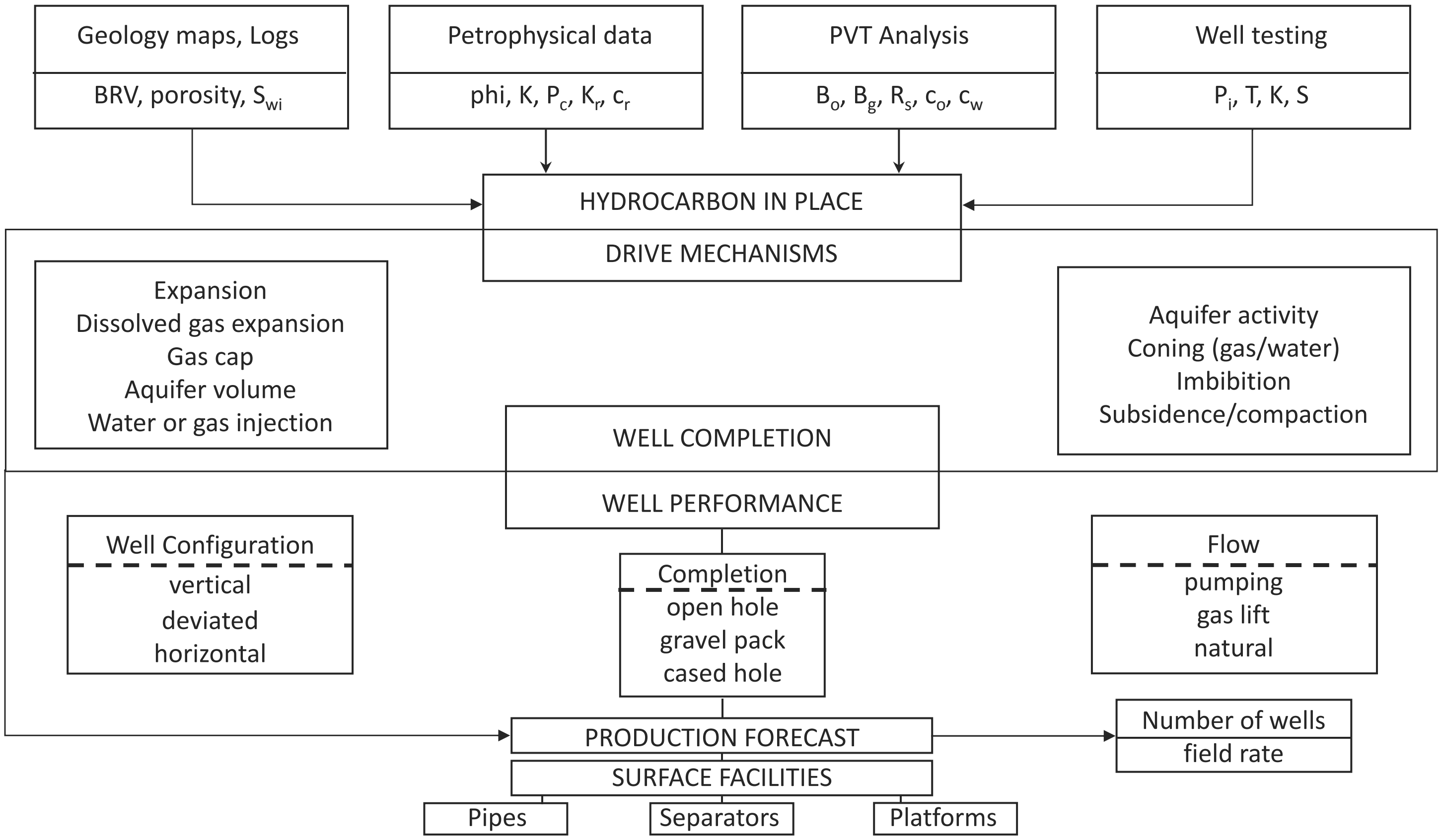
Instructor: Jean-Pascal DEJEAN

E&P workflow – E/D/P



Introduction to drive mechanisms

Field project



Introduction to drive mechanisms

Field development project

- **Field development projects begin with a phase consisting in acquiring, gathering and analyzing geological, petrophysical and fluid data**
- **These data are necessary in order to:**
  - Describe the reservoir as accurately as possible
    - Architecture: top, bottom, lateral extension and closure, any possible compartmentalization (faults), presence and distribution of the heterogeneities
    - Fluids: fluid properties, contacts
  - Estimate volumes in place/accumulations
- **Then drive mechanisms must be determined as early as possible in order to identify the way the reservoir is produced and how it will behave in the future**
  - Estimate the recovery factor and the reserves
  - Determine the production scheme and corresponding production profile
- **Identifying the drive mechanisms is mandatory to help to make a decision for the Field Development Plan (FDP)**

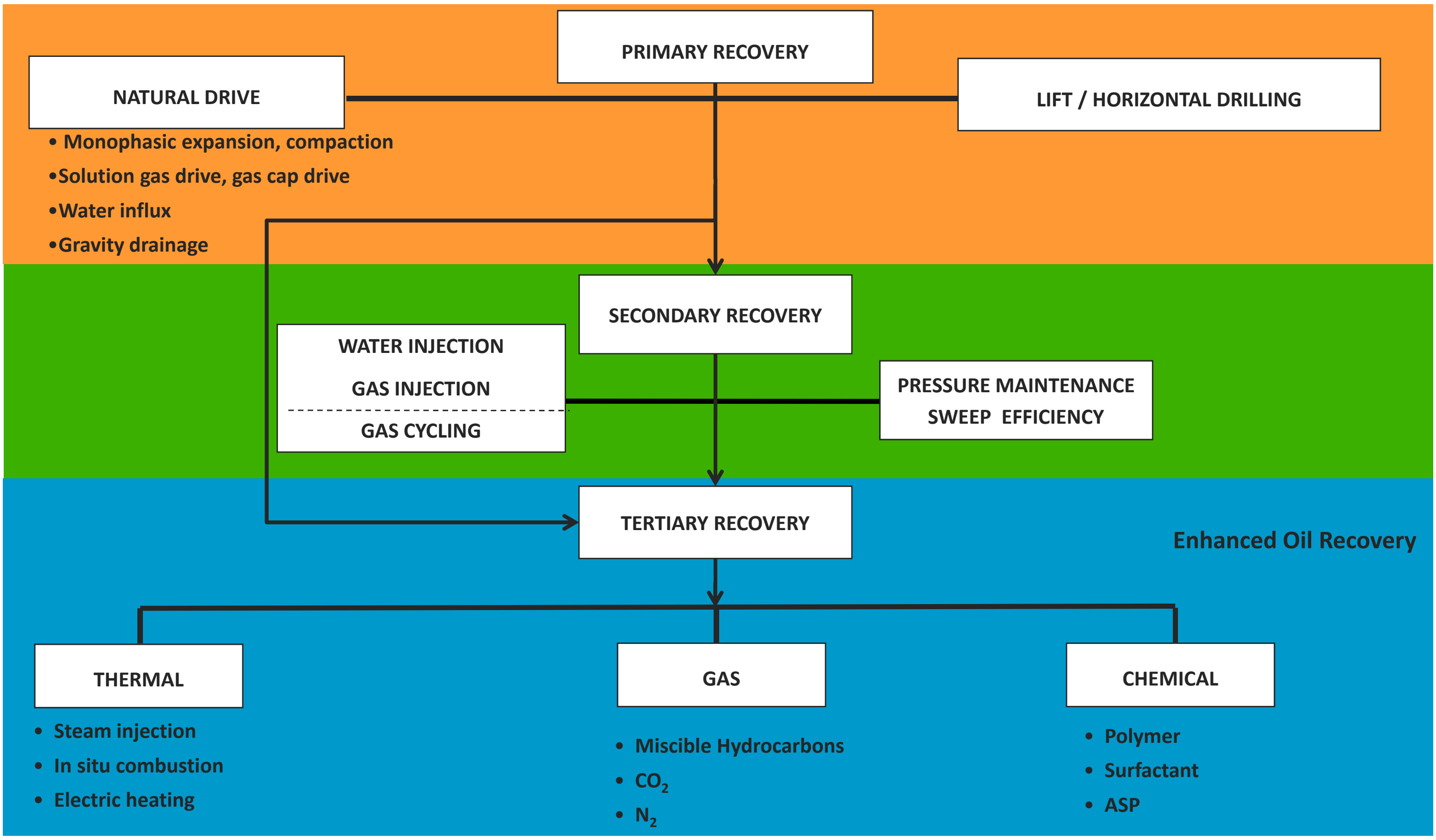
Definitions

Drive mechanisms

- Mechanisms of production of the reservoir
- How is the energy necessary to produce/recover the hydrocarbons provided?

Three types of drive mechanisms/recovery

- **Natural drive/Primary recovery**: the field is produced through its own energy
- **Immiscible fluid injection/Secondary recovery:** energy is provided to the field through injection: water flooding, gas flooding, cycling
- **Enhanced oil recovery/Tertiary recovery**: energy for production is provided through complex techniques:
  - Miscible fluid injection
  - Chemical process: polymer flooding, surfactant flooding
  - Thermal process: steam flooding, in-situ combustion

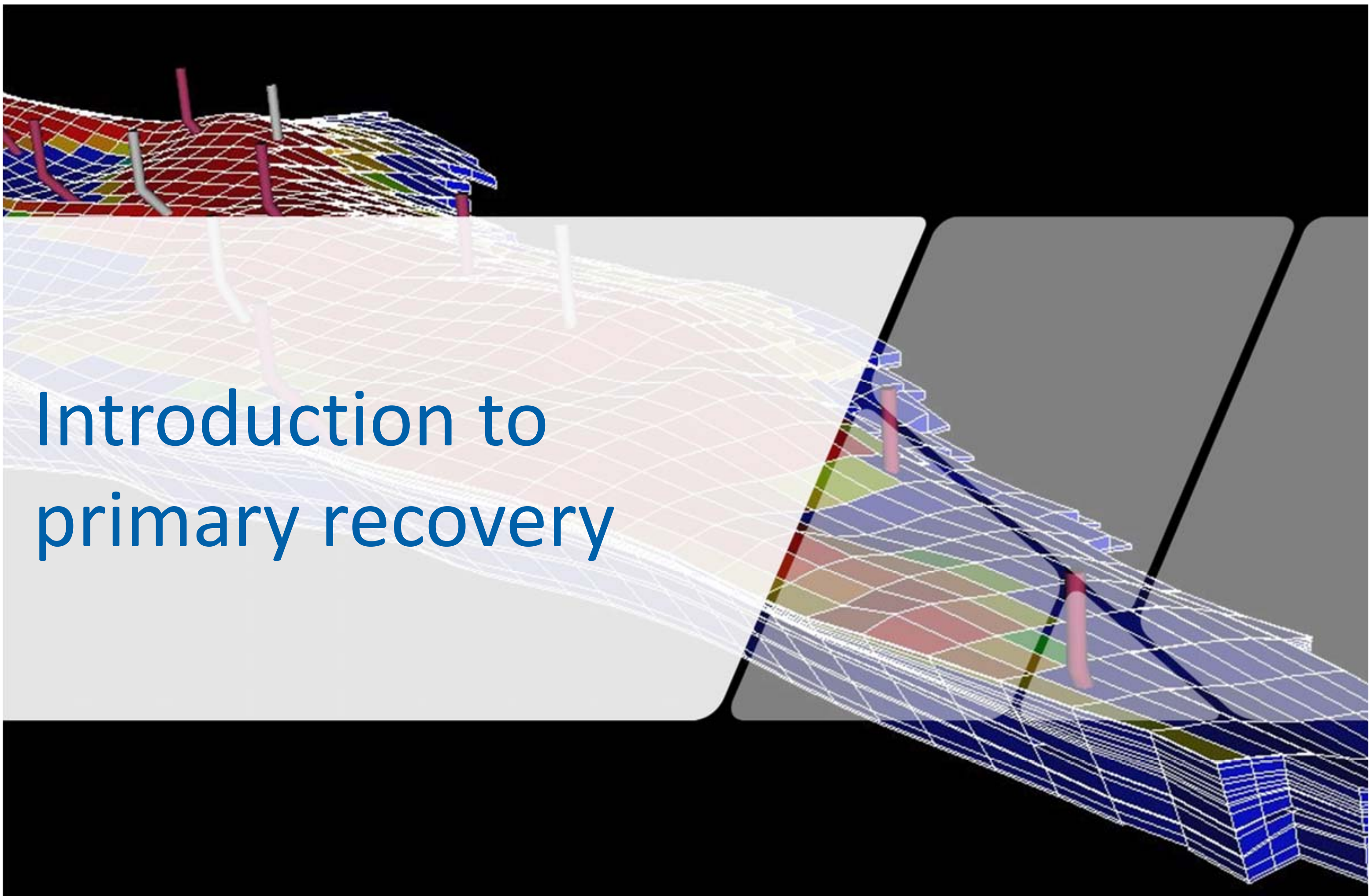


Introduction to drive mechanisms

- **Drive mechanisms refer to the way the energy necessary to produce hydrocarbons is provided to the reservoir**
- **Three types of drive mechanisms**
  - Natural drive/Primary recovery: the reservoir is produced through its own energy
  - Immiscible fluid injection/Secondary recovery: energy is provided through fluid injection: water injection, gas injection, cycling
  - Enhanced Oil Recovery/Tertiary recovery: energy is provided through complex techniques
- **Identifying the drive mechanisms is mandatory in order to help make a decision for the Field Development Plan**
  - Generally, several drive mechanisms may be taken into account, spanning over the whole life of the reservoir
  - IOR/EOR are generally considered from the beginning of the process to establish the FDP but identifying the natural drive mechanisms of the reservoir is always important in order to understand its behavior

Drive mechanisms
Primary recovery

Contents



Introduction to primary recovery

Introduction to primary recovery

Definition

- **Primary recovery refers to the recovery through the natural energy of the reservoir system i.e. natural drive mechanisms**
- **There are various natural drive mechanisms coming from the impact of a number of physical phenomena:**
  - Expansion of reservoir fluids: oil, gas and water
  - Liberation and expansion of solution gas (i.e. lighter part of hydrocarbons mixture) in the case of oil reservoirs
  - Expansion of reservoir rock and reduction of pore volume
  - Pressure support and sweeping from an adjacent active aquifer
  - Action of the gravity forces
- **Natural drive mechanisms have to be understood and evaluated as early as possible in the field history to assess the recovery factor and make a decision about the production scheme of the reservoir**

Reminders: accumulation, reserves and recovery factor

- **Accumulation: volume of oil or gas initially in place**

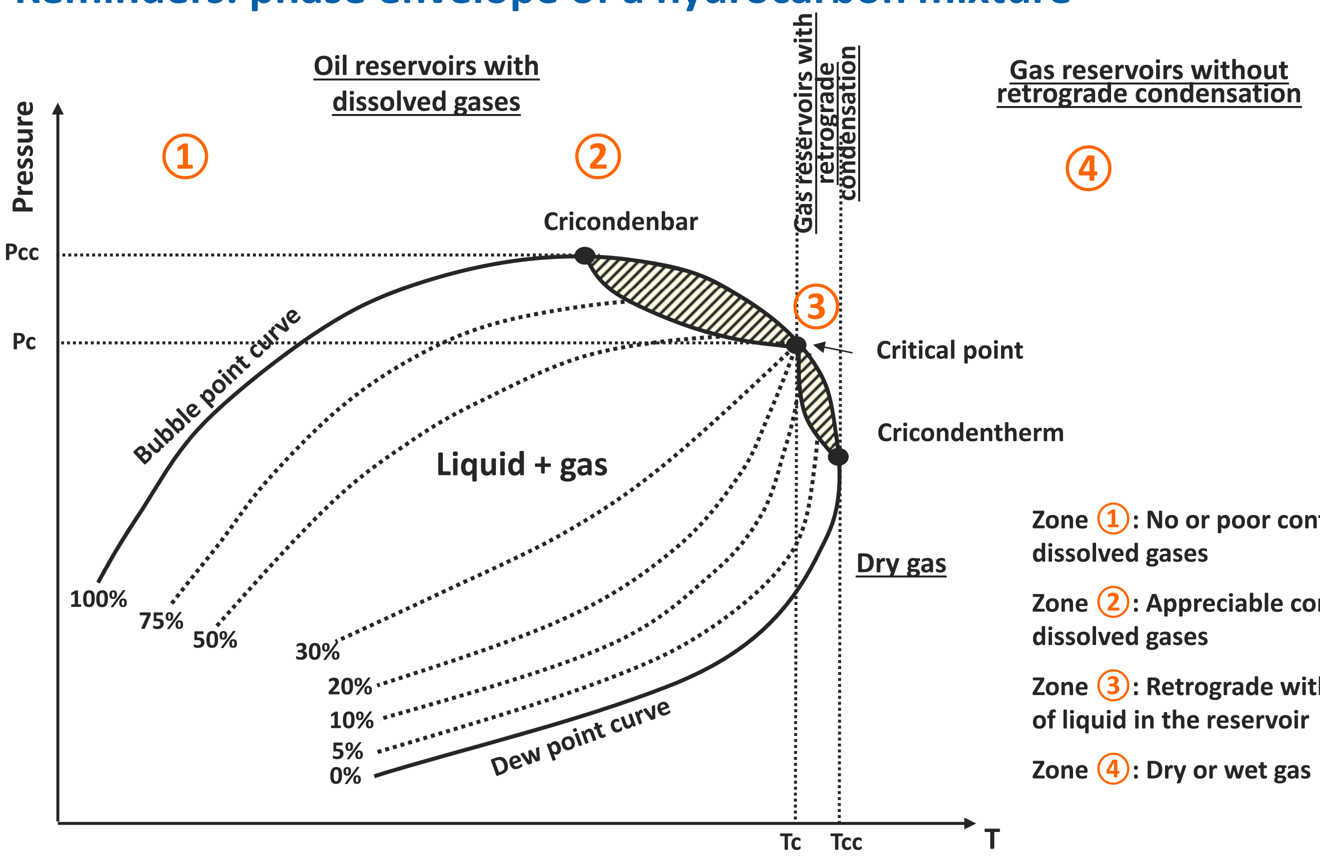
- **Reserves: recoverable volume of oil or gas**

  Reserves = Accumulation x *Rf* %

- **Reserves depend on a geological model, a reservoir model, a development scenario, economics, laws and contracts**

- **All volumes of accumulations (OOIP, OGIP or GIIP) and reserves are expressed in surface (standard) conditions**
  - Standard conditions: 1 atmosphere, 60°F

Reminders: phase envelope of a hydrocarbon mixture



Zone 1: No or poor contribution of dissolved gases

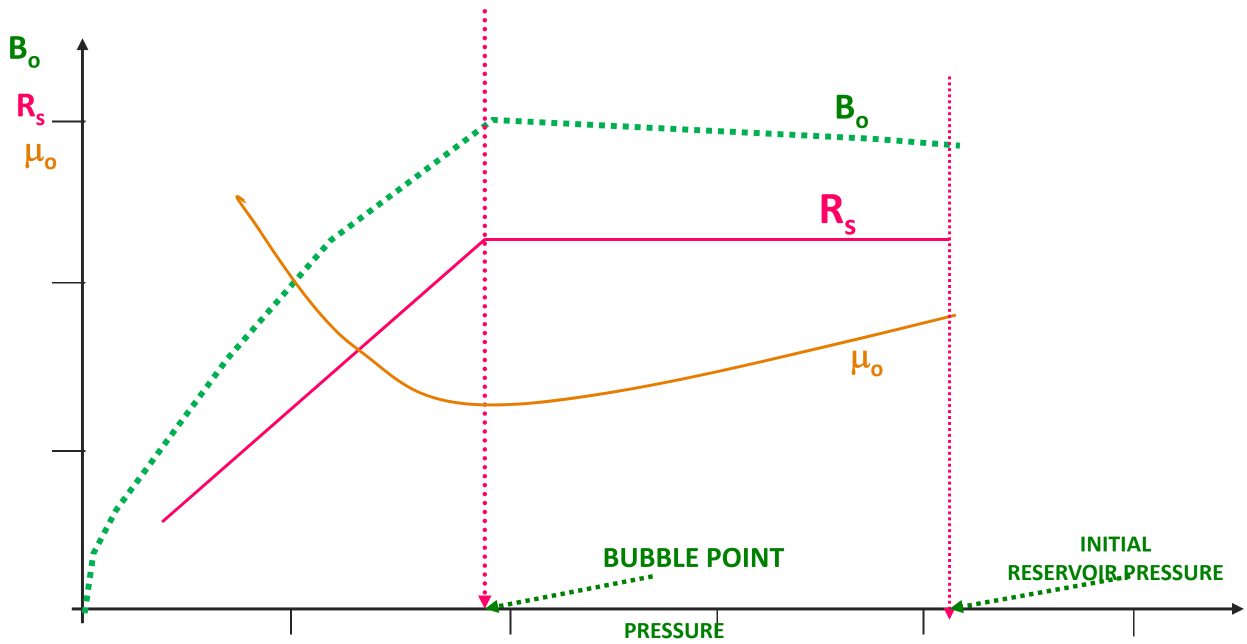
Zone 2: Appreciable contribution of dissolved gases

Zone 3: Retrograde with condensation of liquid in the reservoir

Zone 4: Dry or wet gas

Reminders: PVT parameters against pressure

Evolution of the main reservoir properties with pressure



Reminders: compressibility

- **Compressibility is related to the relative change in volume of an element (gas, liquid, solid) when it is submitted to a variation of pressure**

$$c = -\frac{1}{V}\frac{dV}{dP}$$

$$dV = -cV dP$$

- **Typical compressibility values in the reservoir**
  - Oil: c_0 = 0.7 to 3 x 10^{-4} bar $^{-1}$ (above bubble point)
  - Water: c_W = 0.4 to 0.7 x 10^{-4} bar $^{-1}$
  - Pore volume: c_P = 0.3 to 1.5 x 10^{-4} bar $^{-1}$
  - Gas: c_g = 7 to 145 x 10^{-4} bar $^{-1}$ (highly dependent on the pressure of the reservoir)
- **Compressibility is the physical parameter behind fluid and pore volume expansion and compaction and one of the main parameters involved in natural drive mechanisms**

Reminders: production parameters

- **Typical parameters of interest to monitor production and assess the performance of a recovery mechanism and related production scheme**

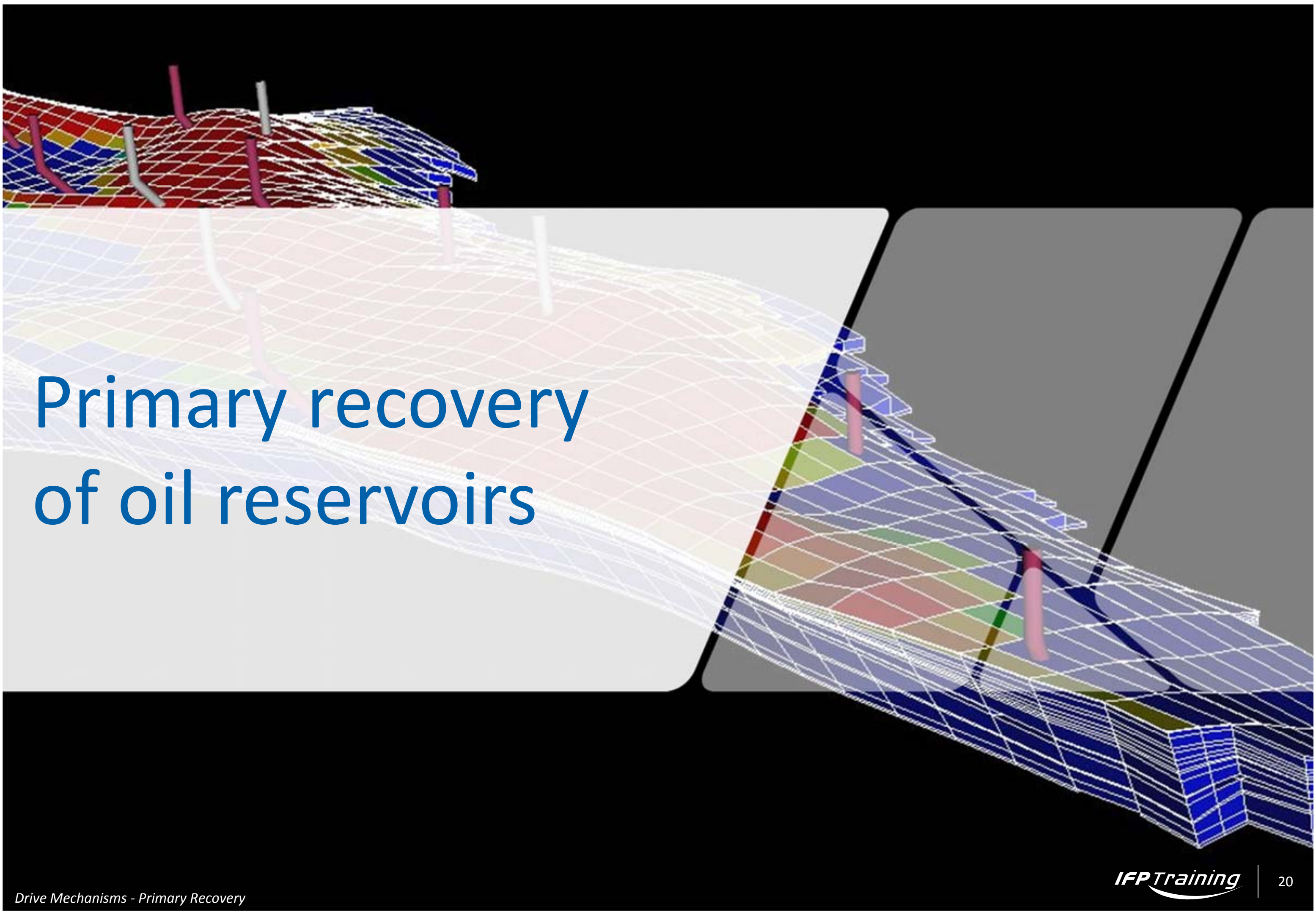
  - **GOR = Gas Oil Ratio**
    - Instantaneous GOR: $$GOR = \frac{Gas\ flowrate@S.C}{Oil\ flowrate@S.C.}$$
    - Average GOR: $$GOR_{av} = R_p = \frac{Produced\ Gas\ volume@S.C}{Produced\ Oil\ volume@S.C.} = \frac{G_p}{N_p}$$
    - There might be large differences between the two at a given moment of the production!
    - Average GOR is used for material balance calculations (see below)

  - **WC = Water-Cut**
    - Instantaneous WC: $$WC = \frac{Water\ flowrate@S.C}{Water\ flmowrate + Oil\ flowrate@S.C.}$$

Primary recovery for oil and gas reservoirs

- **Oil reservoirs show four main natural drive mechanisms that are split into two groups**
  - **Depletion drive:** the reservoir is not in contact with a large active aquifer
    - **Monophasic fluid expansion & pore volume compaction**
    - **Solution gas drive**
    - **Gas cap drive**
  - **Natural water drive:** the reservoir is in contact with a large active aquifer providing **pressure support** and **sweeping of the reservoir**

- **Gas reservoirs are mainly concerned with monophasic fluid expansion**
  - **Depletion drive**: very good performance
  - **Natural water drive:** poor performance!
  - Special case: gas condensate reservoir
    - **Try to keep above dew point pressure!**



Primary recovery of oil reservoirs

Natural depletion – Undersaturated oil

General principle and performances

- **At pressures above bubble point pressure, oil, connate water and rock are the only materials present in the reservoir**
- **As the pressure drops due to the production, the reservoir fluids expand while the pore volume compacts due to their individual compressibilities**
- **As a result of expansion of fluids and reduction of pore volume, more oil (and possibly water) is forced out to the wellbore**

- **Typical performances**
  - Reservoir pressure **declines rapidly** while **GOR remains constant and equal to R_s, the solution GOR**
  - **Water-Cut is generally nil** since this drive mechanism occurs very early in the life of the reservoir, when production is still anhydrous
  - Volume variations that are behind this mechanism are related to the compressibilities of oil, water and pore volume, which are generally quite low: as a consequence the **expected recovery factor is very low, in the range of a few % only**

Compaction drive
General principle and performances

- **During natural depletion (no or weak pressure support), the fluid pressure FP decreases, hence the grain pressure GP increases and the pore volume shrinks according to pore compressibility:**

$$c_p = \frac{1}{PV} \cdot \frac{\Delta(PV)}{\Delta P}$$

- **Generally, c_p is low (0.3 to 1.5 x 10^{-4} bar $^{-1}$) and assumed constant all along the monophasic natural depletion**
  - Pore volume compressibility may be neglected for sake of simplicity leading to an assumption of constant pore volume

- **However, in some cases, typically reservoirs with high initial porosity, c_p may increase leading to significant additional oil recovery**
  - **Compaction drive mechanism may result in Recovery Factor up to 20%**

Compaction drive
General principle and performances – 2

- **Pore volume compressibility and bulk rock compressibility**
  - Bulk rock compressibility is the one that is measured in laboratory (through SCAL) and it is defined as:

$$c_b = \frac{1}{BV} \cdot \frac{\Delta(BV)}{\Delta P} = \frac{1}{h} \cdot \frac{\Delta h}{\Delta P}$$

  - As $\Delta(BV) = \Delta(PV)$ we get:

$$c_p = c_b \frac{BV}{PV} = c_b/\emptyset$$

- **Generally high c_p are associated to overpressure and/or high initial porosity**
  - When fluids are produced out of the pore volume, the fluid pressure decreases leading to an increase in the Grain Pressure and a decrease in porosity thus forcing fluids out of the pore volume
  - The process generally results in a mechanical failure of the rock and a collapse of the porous matrix => compaction drive is often associated with **surface subsidence**

Compaction drive

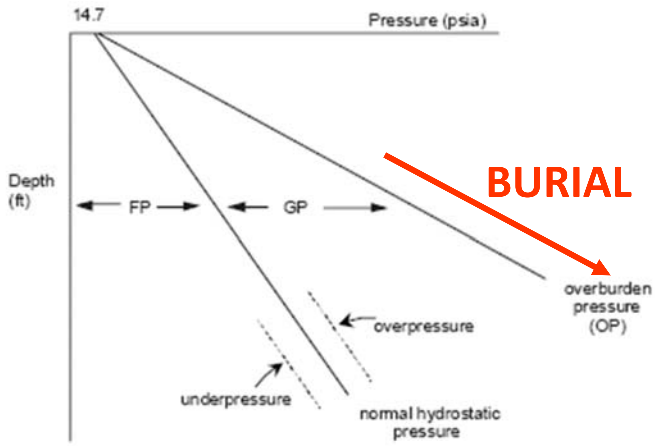
Pressures in the reservoir

- **Overburden Pressure**
  - Overburden pressure is the sum of the fluid pressure and grain pressure

$$OP = FP + GP$$

$$OP = \frac{Weight\ (fluid + rock\ matrix)}{Area}$$

  - OP gradient is about 2.5 bar/m or 1 psi/ft



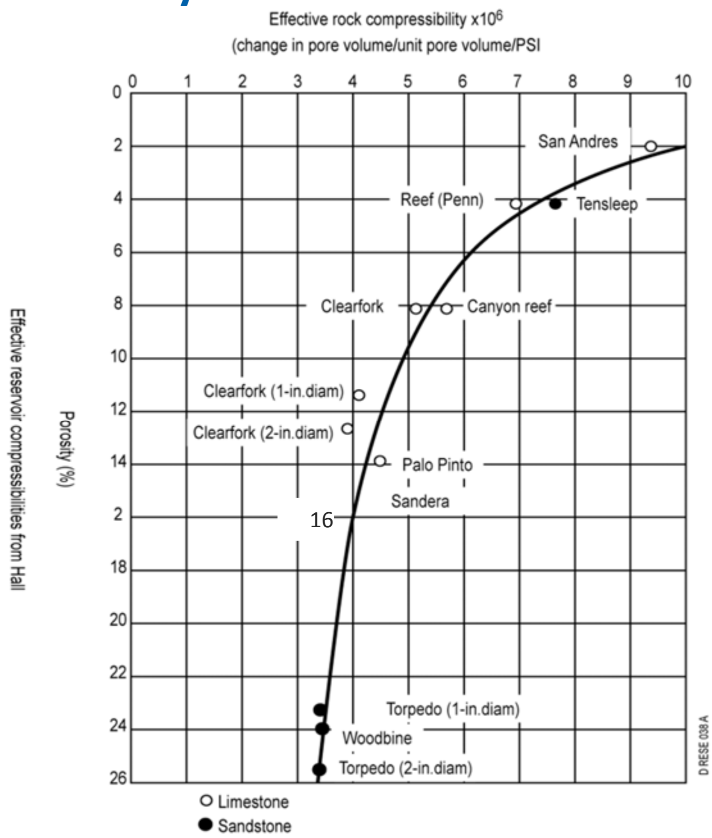
- **Fluid pressure**
  - Fluid pressure or formation pore pressure is the pressure acting upon the fluids (water, oil, gas) trapped within the pores of the formation
  - FP gradient is about 0.1 bar/m or 0.45 psi/ft

Compaction drive

Pressure regimes in the reservoir

- **There are three types of fluid pressure regimes**
  - **Hydrostatic** pressure: the pressure corresponding to the weight of a vertical column of water up to surface
  - Subnormal pressure or **underpressure**: a fluid pressure less than the normal hydrostatic pressure
  - **Overpressure**: a fluid pressure superior to normal hydrostatic pressure
- **Overpressure**
  - may be caused by compaction, formation uplifting, faulting, repressurization, hydrocarbon generation, massive evaporite deposition, mineral phase change etc. actually a rapid change in the strain system so that fluid pressure has not enough time to reequilibrate => generally associated to low permeability or permeability barriers
  - needs the reservoir to be sealed off from the surrounding strata => several pressure regimes may exist if reservoir is compartmentalized
- **Overpressure plays an important role in the compressibility and possible failure of reservoir rock**

Compaction drive
Compressibility chart



Rock compressibility (pore volume compressibility) increases when porosity decreases

Compaction drive
Ekofisk

- **Ekofisk: a giant offshore field in the Norwegian North Sea**
  - Fractured chalk section at about 10,000 ft SS with pay height of about 1,000 ft at crest
  - $STOOIP \cong 6000\ MMstb$
- **Ekofisk and compaction drive**
  - Reservoir was overpressured by about 2,000 psi and initial chalk porosity was very high: 25 to 48% => pore compressibility increased from 6.10^{-6} psi^{-1} to a maximum of 10^{-4} psi^{-1} providing 30% of total drive energy
- **Ekofisk and subsidence**
  - First well drilled in 1969
  - Full field production began by 1974
  - By 1984, due to compaction, seabed subsidence mounted up to 10 feet => platform legs had to be cut and new legs section were added up to 20 ft !!!

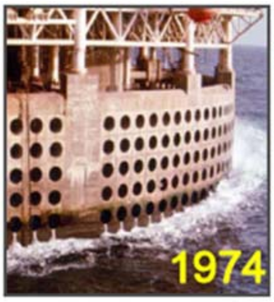
Compaction drive

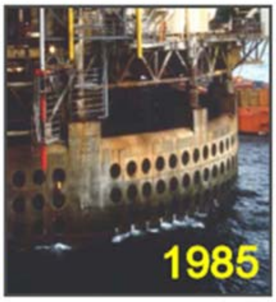
Ekofisk - 2

GEV: Chalk fields - Impact of subsidence

- Surface facilities to be replaced:
  - Whiskey WHP replaced by SS Wat. Inj. 2010
  - Valhall VRD 2010/2011 (Living Quarters and Process)
  - Ekofisk Living Quarters 2013
  - Eldfisk II 2015 (WHP + LQ+ Process)
- Wells to be constantly redrilled (average well life 10-15 years)
- 4D effect visible on seismic: LoFS

PLATFORM	SUBSIDENCE RATE 12 month (cm/yr)	SUBSIDENCE RATE 4 month (cm/yr)	SUBSIDENCE RATE 12 month (cm/yr)	SUBSIDENCE RATE 4 month (cm/yr)	TOTAL SUBSIDENCE (meters)
2/4 HOTEL	11.5	14.4	11.7	14.2	8.277
2/4 ALPHA	13.5	14.6	13.7	15.2	[illegible]
2/4 BRAVO	8.2	8.2	8.8	7.1	5.412
2/4 J*	13.7	16.8	13.8	14.6	3.628
2/7 ALPHA*	2.4	2.9	2.5	2.7	1.644
2/7 BRAVO*	4.6	4.4	4.2	5.1	1.728
2/7 EMBLA	0.9	1.4	0.9	1.1	0.969





Ekofisk II replaced in 1998 the old Ekofisk I facilities

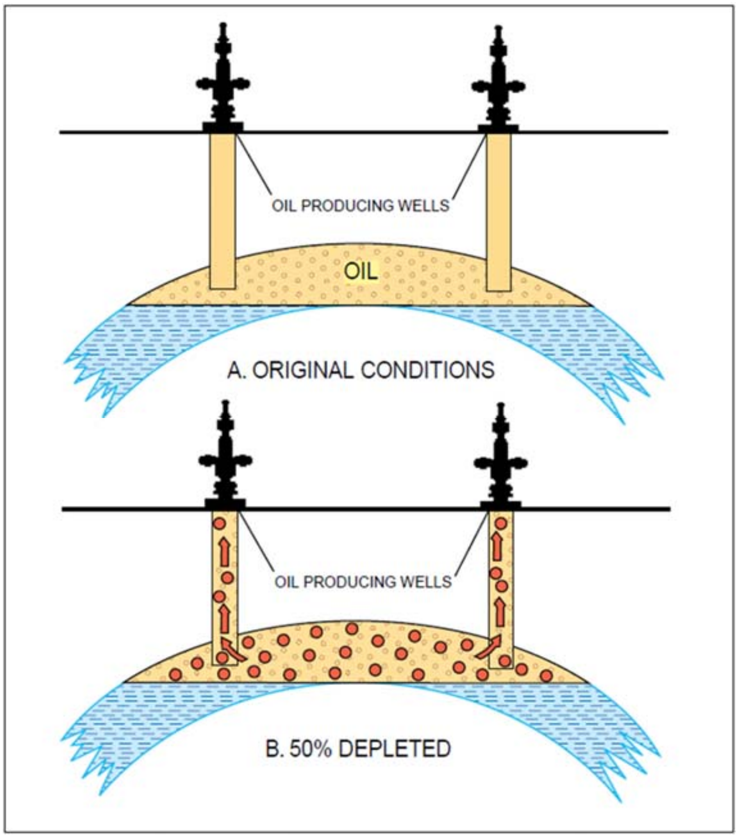
TOTAL

2

Solution gas drive

General principle

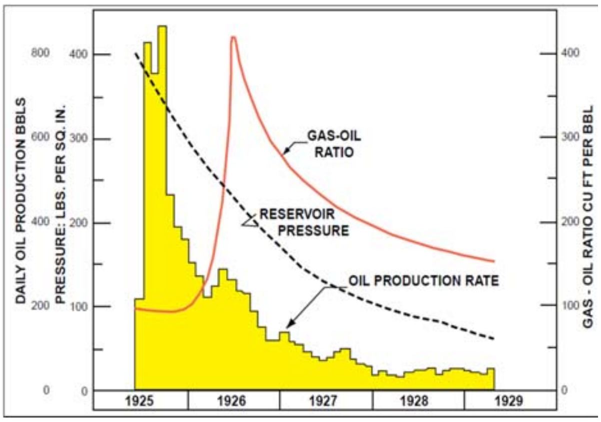
- **In this type of reservoir, the main source of energy results of free solution gas liberating from the oil and subsequent expansion of this solution gas as the pressure is further reduced.**
- **Oil displacement by the expansion of the gas liberated from solution as pressure decrease below the bubble point pressure**
  - As pressure further decreases, more gas is released from solution
  - Fluids and rock compressibility effects can be neglected vs. expansion of the liberated gas => **pore volume is typically considered to be constant**

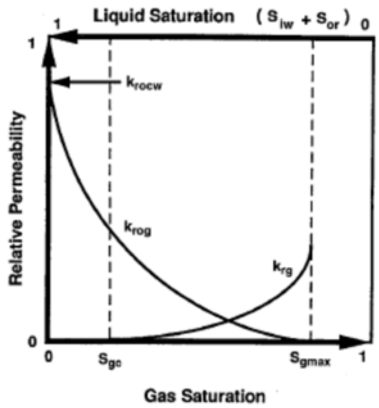


Solution gas drive

Performances

- **Typical reservoir performances**
  - Solution gas drive reservoirs exhibit typically rapid reservoir pressure decline and, correspondingly, rapid oil production decline but less than in the case of natural depletion; after blow-down, the decline is very fast for both pressure and production
  - GOR quickly reaches a maximum value, before declining rapidly (**reservoir blow-down**)
  - Oil production **gets more and more difficult as more and more solution gas is liberated**
    - Indeed, as a result of the increase in gas saturation in the reservoir, there is an **unfavorable evolution of relative permeabilities** and oil flow rate decreases while gas flowrate increases
    - Furthermore, the **oil viscosity increases** since the lighter components of the oil get out
  - The recovery factor **typically ranges from 5 up to 25 %**



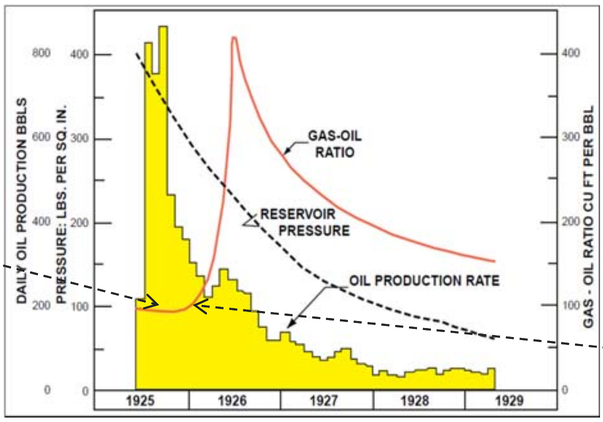


Solution gas drive

Performances – 2

- **Typical reservoir performances for undersaturated oil expansion followed by solution gas drive**
  - The change in the slope of the pressure curve indicates the bubble point
  - GOR is constant as long as $P > P_b$
  - As soon as $P < P_b$ solution gas begins to be liberated, but it is not mobile as long as $S_g < S_{gc}$ where S_{gc} is the critical gas saturation
    - S_{gc} is typically 5% but can go up to 10% for vuggy carbonates

GOR is slightly decreasing since liberated gas is not mobile yet

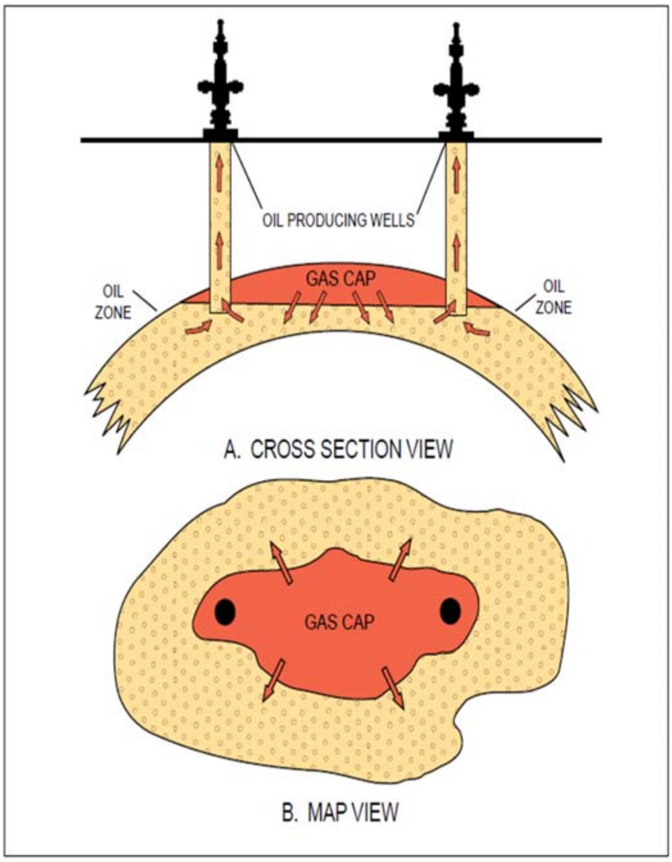


$S_g > S_{gc}$, liberated gas is mobile and GOR increases

Gas Cap Drive

General Principle

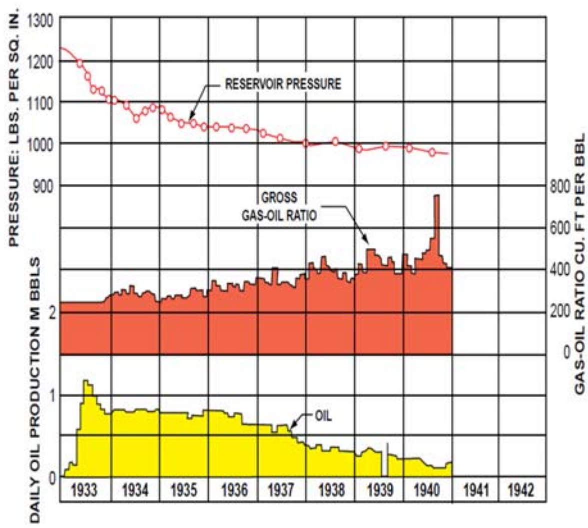
- The pressure decline associated with the production of oil allows the gas cap to expand thus providing further energy for additional oil production
- Gas cap drive effectiveness depends on
  - A large (initial or secondary) gas cap
    - The initial pressure in the oil column @ GOC is equal or very close to P_b and **solution gas drive occurs together with gas cap drive**
    - The liberated solution gas may form a secondary gas cap provided we have high vertical permeabilities and a good reservoir homogeneity
  - Good contact between oil pool and gas cap
  - Good gravity segregation characteristics
    - Thick oil zone – High dip angle
    - High permeability – especially vertical permeability



Gas cap drive

Performances

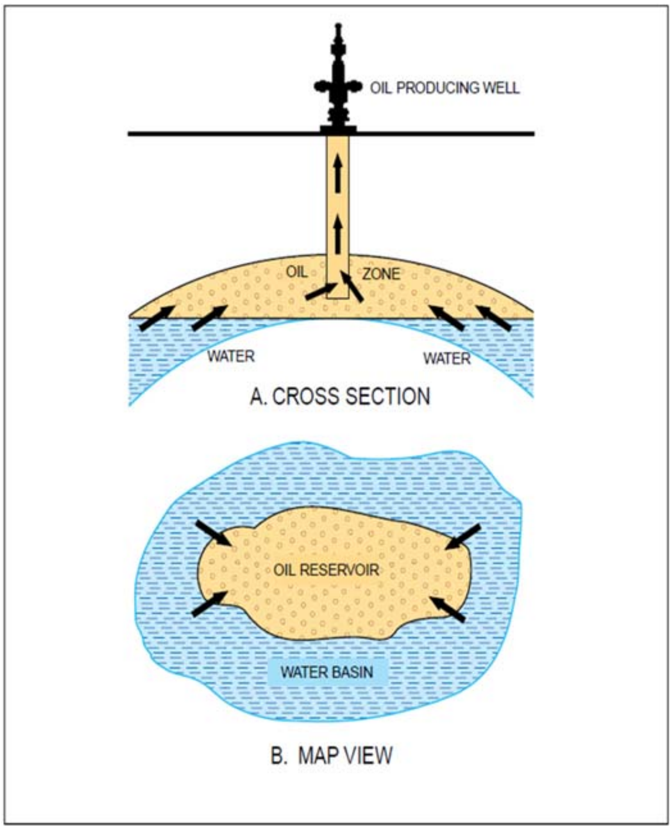
- Typical reservoir performances
  - A gas cap drive exhibits typically a **slow reservoir pressure decline** and a **slow oil production decline**
  - GOR rises slowly and progressively but there is no maximum (no reservoir blow-down)
  - Producing slowly will allow the liberated solution gas to rise up to the gas cap (and possibly form a secondary gas cap) and will help prevent **coning**
    - Coning is due to the higher mobility of gas (and water) compared to oil
    - Gas coning is very difficult to avoid and almost impossible to control => we need to perforate lower (use Neutron Behind Casing log to know where is the GOC) or finally shut the well down
  - The recovery factor is generally higher than for solution gas drive reservoirs, **20% up to 40%,** and it highly depends on the **vertical permeabilities**
  - **Take care not to produce the gas cap!**



Water drive

General principle

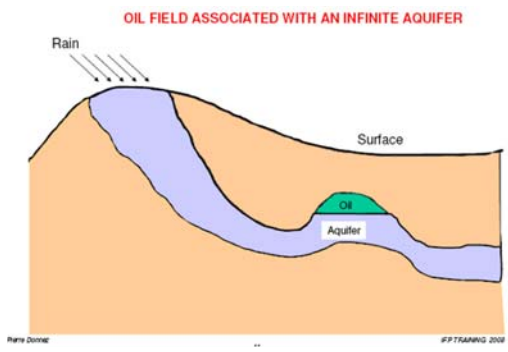
- **Energy is provided by a water influx from a nearby aquifer into the reservoir resulting in pressure support and sweeping**
  - The pressure decrease in the reservoir under production is transmitted to the water zone
  - Hence, the water zone shows a pore volume reduction and a water expansion thus **leading to water production into the oil zone**
- **The water drive effectiveness depends on the aquifer properties rather than the reservoir properties**
  - In the short times, the **aquifer transmissibility** that rules the time needed for the aquifer to react (i.e. produce water into the reservoir)
  - In the long times, the **aquifer size** that rules the volume of water produced in the reservoir



Water drive

Types of aquifers – infinite aquifers

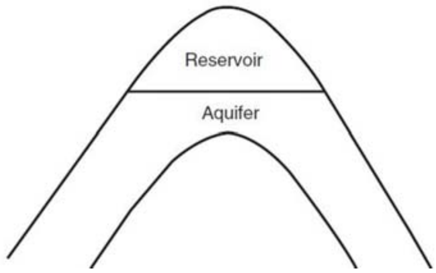
- **Degree of pressure maintenance**
  - Active/ partial / limited water drive
- **Active water drive relates to very active and effective aquifers with water encroachment**
  - Typically swallow aquifers connected to surface or aquifers connected to mountain basement => **infinite aquifers**
  - Infinite aquifers do not exist actually and they refer to formations where pressure changes at the water/oil contact never reach the outer boundary => **outer boundary pressure remains constant and equal to the initial aquifer/reservoir pressure**
  - Bounded aquifers refer to a formation where pressure changes at the water/oil contact reach the outer boundary i.e. the aquifer outer limit is affected by the water influx into the oil pool => **outer boundary pressure changes with time**



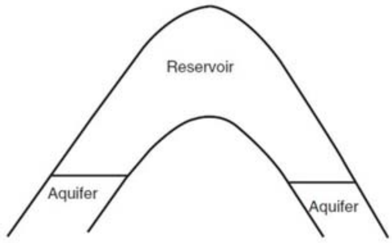
Water drive

Types of aquifer geometries

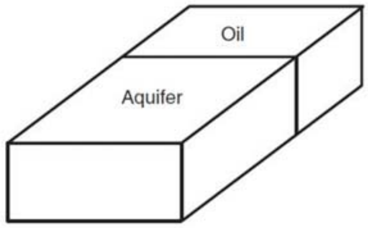
- **Radial bottom-water drive**
  - Radial flow from a large contact area below the reservoir
  - Significant vertical flow: driving parameter is $\boldsymbol{k_v}$



- **Radial edge-water drive**
  - Radial flow from the side of the reservoir
  - No significant vertical flow : driving parameter is $\boldsymbol{k_h}$



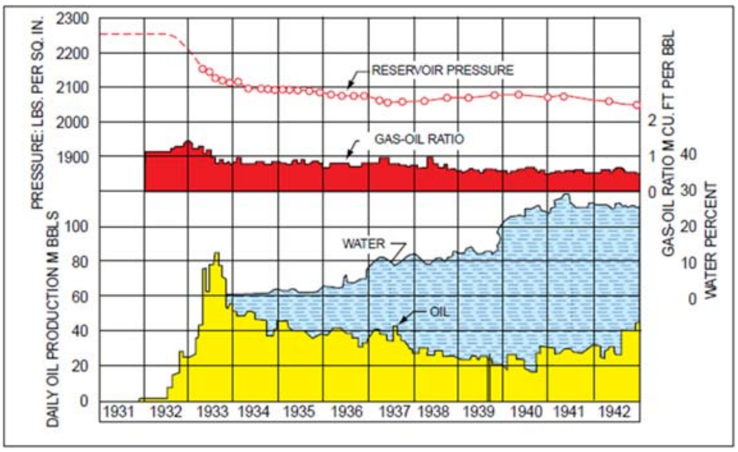
- **Linear edge-water drive**
  - Linear flow from one side of the reservoir with a constant cross-section area



Water Drive

Performances

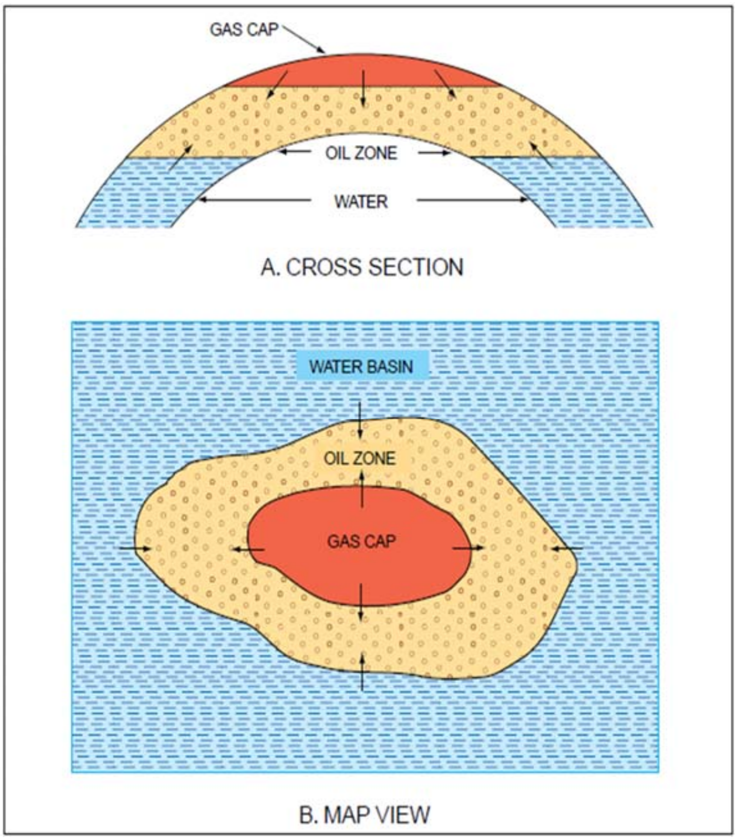
- **Typical reservoir performances**
  - The total fluid rate is generally supposed to be constant i.e. water influx may be equal to the total reservoir production rate thus **providing a full pressure support** (reservoir pressure is maintained)
  - If reservoir pressure is kept above bubble-point, GOR remains constant
  - A water drive reservoir generally shows a steady increase in Water-Cut (and WOR) and a decrease in oil production
  - **The recovery factor is generally high and itcan reach value as high as 40 to 60 %**



Combined drive mechanisms

General principle and gravity drainage

- **Several drive mechanisms may exist at the same time in the reservoir**
  - Depletion drive and a weak water drive
  - Solution gas drive with a small gas cap and a weak water drive…
  - The relative importance of each mechanism may vary along the life of the reservoir
- **Case of gravity drainage**
  - Generally not the main drive mechanism but rather an additional drive mechanism
  - Gravity drainage effectiveness is related to **fluid segregation** in the reservoir
    - High contrast of gravity between the fluids
    - High reservoir dippage
    - High vertical permeabilities
    - Low production flowrates
  - **It may result in very high Rf, up to 60%**



Primary recovery of oil reservoirs

- **Primary recovery refers to natural drive mechanisms that can be split in two groups:**
  - Depletion drive: the reservoir is not in contact with a large active aquifer
    - Monophasic fluid expansion & pore volume compaction
    - Solution gas drive
    - Gas cap drive
  - Water drive: the reservoir is in contact with a large active aquifer that maintains pressure
- **From the study of the drive mechanisms, we can get material balance equations that are a basic tool for reservoir engineers to analyze the reservoir behavior and performance**

Undersaturated oil expansion and compaction drive

- The natural depletion of undersaturated oil reservoirs is the simplest drive mechanism
- It is based on expansion of volumes of oil and connate water and compaction of pore volume due to the pressure drop in the reservoir
- Due to the low compressibilities of fluids and pore volume, the expected R_f is low, typically a few %
- Alternatively, in some cases (overpressure and/or high porosity), the compressibility of pore volume can reach high values causing reservoir compaction and leading to higher values of R_f, typically 20%
- However, compaction drive may cause surface subsidence

Solution gas drive

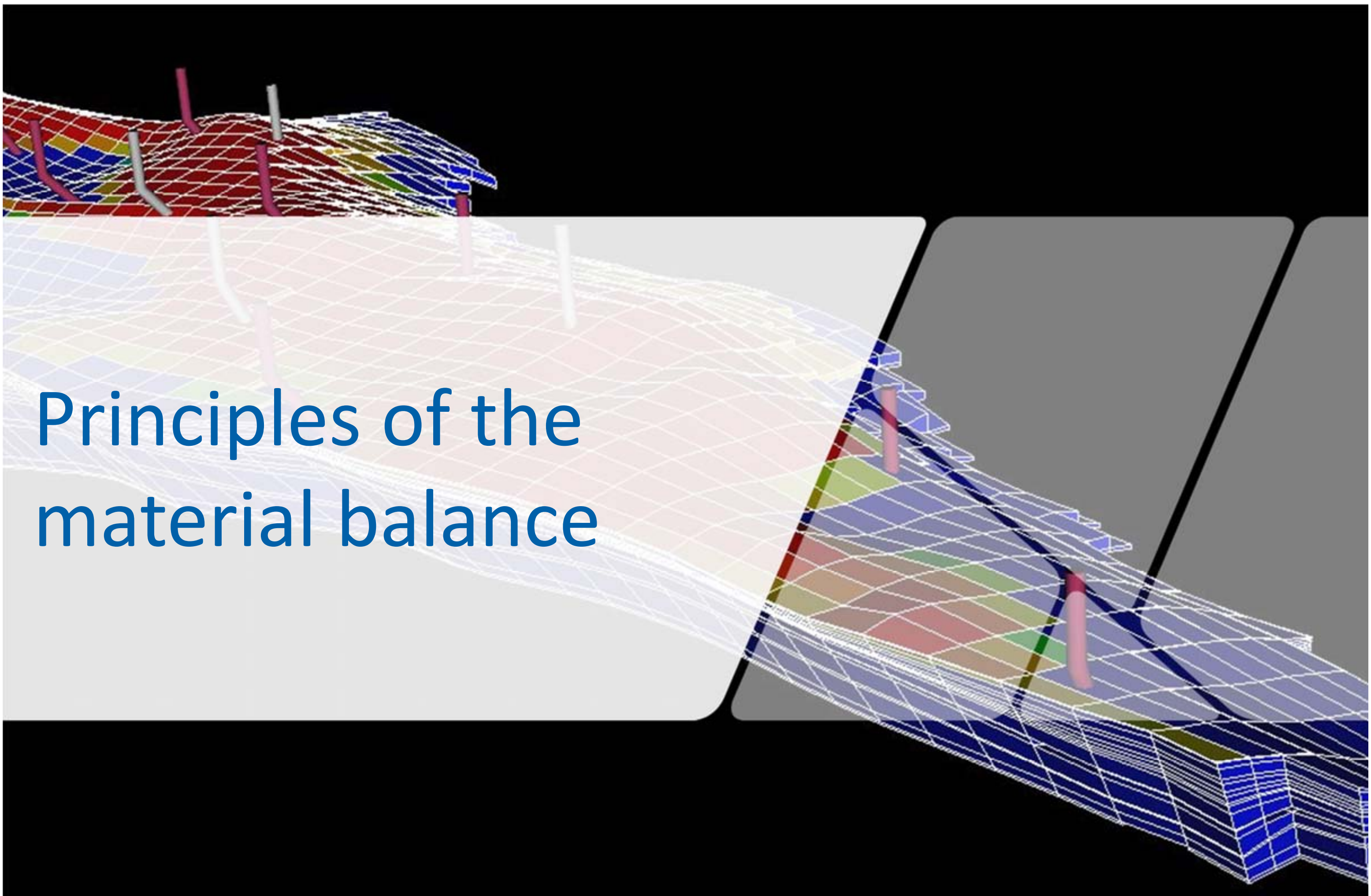
- As the pressure drops below the bubble point pressure, solution gas is liberated from the oil in the reservoir, it expands and helps produce the oil
- Solution gas drive reservoirs typically show rapid reservoir pressure decline and, correspondingly, rapid oil production decline albeit less rapid than for undersaturated oil expansion drive.
- GOR rises rapidly from initial value to a maximum value before declining rapidly (reservoir blow-down)
- The recovery factor typically ranges from 5 to up to 25 %

Gas cap drive

- The pressure decline associated with the production of the oil causes the gas cap to expand
- To be effective a large gas cap is necessary (initial or secondary gas cap formed from solution gas)
- An efficient gas cap drive mechanism exhibits typically slow reservoir pressure decline and a slow oil production decline while GOR rises slowly and progressively (no reservoir blow-down)
- Rf is generally higher than for solution gas drive reservoirs, typically 20-40%, and depends highly upon the vertical permeabilities
- One shall ensure not to produce the gas cap and to limit gas coning at the producers

Water drive

- The pressure primary source of energy is supplied by water influx (from an adjacent aquifer) into the reservoir
- The energy for this water influx comes from the compaction of the pore volume and the expansion of water in the aquifer
- Water drive effectiveness depends on the aquifer properties and not on the reservoir ones; the two key parameters are the aquifer transmissibility in the short times and the aquifer size in the long times and
- The total fluid rate remains generally constant, with a sharp increase in Water-Cut while GOR remains constant as long as pressure is maintained above P_b
- The recovery factor typically ranges from 30 to 60 %



Principles of the material balance

Principles of the material balance

Calculation methods for production/reserves forecast

- **Simplified methods**
  - Material balance: single cell model with simplified expression of the recovery factor
  - Decline rate analysis: history match of flowrate (wells, field) in order to forecast reserves

- **Advanced methods**
  - Numerical models: building a model in order to mimic the behavior of the actual reservoir
    - Numerical models allow to handle heterogeneities and related uncertainties at all scales
    - Numerical models allow to handle complex fluid behavior

Introduction to primary recovery

Material balance vs. numerical simulation

The geological/reservoir models are not required

- Production data
- Pressure data
- PVT data

Material balance

Accumulation
Identification of production mechanisms
Production forecast (cumulative)

The geological/reservoir models are needed

- Production data
- Petrophysical properties
- PVT data

+

Volume of hydrocarbons in place
Production mechanisms

Simulations

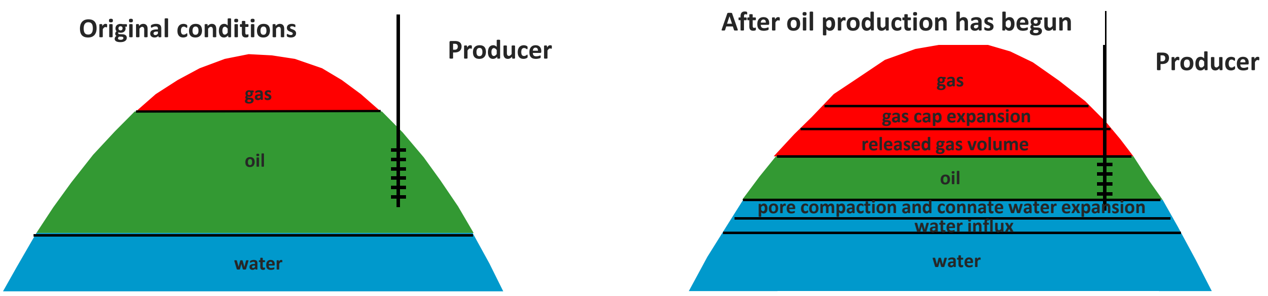
Pressure value forecast
Saturation value forecast
Production forecast (flowrate and cumulative)

Principles of the material balance

General principle

- **Material Balance = balance regarding the volumes of fluids in the reservoir**
  - Assuming the reservoir pore volume is 100% filled with fluids, in reservoir conditions:
    - Initial Vol. fluids = Remaining Vol. fluids + Change in pore volume + Vol. of injected or entered fluids

    Or
    - Net withdrawal fluids volume (withdrawal - injection) = Expanded vol. of fluids in the system + Vol. of cumulative water influx
  - A kind of "equation of continuity" for the reservoir/part of the reservoir over a finite time interval => the simplest reservoir simulation model (1 cell!)
  - **It requires a well established pressure regime over the reservoir or part of the reservoir**



$P_i, B_{oi}, B_{gi}, R_{si}$ $\qquad$ P, B_o, B_g, R_s

Conditions for applying the material balance

- **There are no 'sufficient' conditions for the meaningful application of the material balance to a given reservoir, but there are two 'necessary' conditions that must be satisfied**
  - **There should be adequate data collection (production data/pressure data/PVT), both in quantity and quality**, otherwise the attempted application of the technique becomes meaningless.
    - Production data are typically average parameters e.g. average GOR (not instantaneous GOR) => they must be calculated
    - Pressure data classically refers to reservoir static pressure not bottom hole flowing pressure => it must be measured or evaluated
  - **It must be possible to define an average pressure decline trend for the reservoir or part of the reservoir**
    - The pressure dependent PVT parameters and Δp are evaluated as a function of time using this decline trend
    - The pressure decline trend may be defined separately on various compartments of the reservoir => The material balance may be applied separately to the various compartments

Accumulation, production and injection

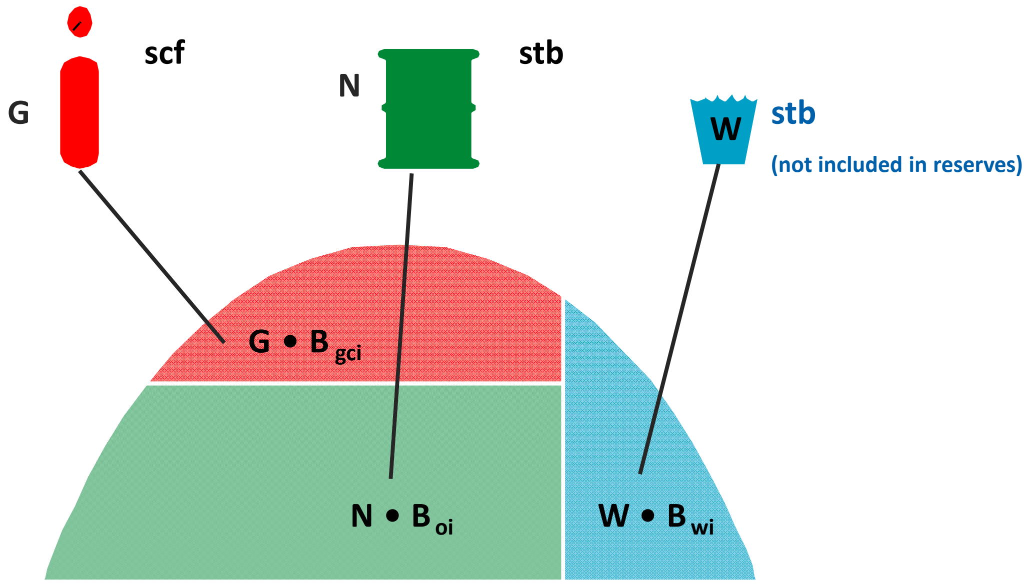
- **Evaluation of accumulation (to be compared with volumetric methods)**

	Oil	Gas	Water
Accumulation	**N**	**G**	**W**
Cumulative production	N_p	G_p	W_p
Cumulative injection		G_{Inj}	W_{Inj}
All volumes in standard conditions			

- **We need to know the Formation Volume Factors to convert from surface to reservoir conditions**

Principles of the material balance

Fluid volumes before production



Surface Volumes

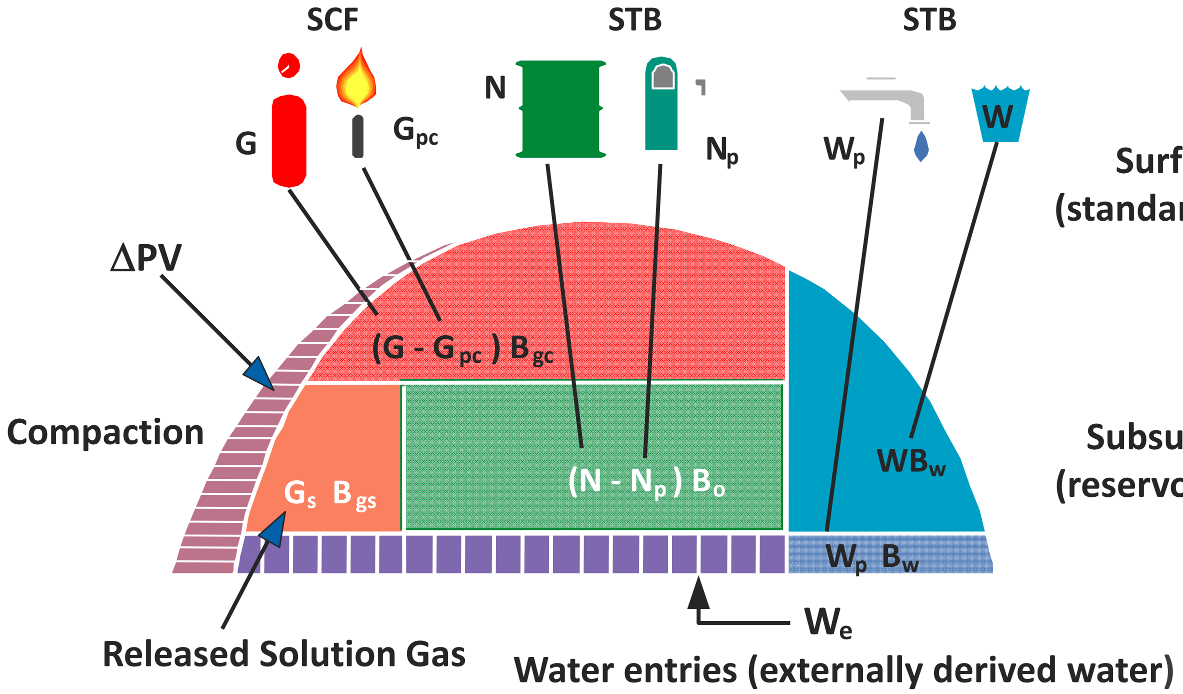
(standard m^3,
stb Standard Barrels
or scf Standard Cubic Feet)

Subsurface Volumes

(reservoir barrels
reservoir m^3)

Principles of the material balance

Fluid volumes after production



Surface volumes
(standard m^3, stb or scf)

Subsurface volumes
(reservoir m^3 or barrels)

Symbols and units

Symbols	UNITS	US units	Metric
μ_g	Gas viscosity	cP	cP
μ_o	Oil viscosity	cP	cP
B_g	Gas formation volume factor at pressure P	Bbl/Mscf	vol/vol
B_{gi}	Initial gas formation volume factor	Bbl/Mscf	vol/vol
B_o	Oil formation volume factor at pressure P	Bbl/stb	vol/vol
B_{oi}	Initial oil formation volume factor	Bbl/stb	vol/vol
B_t	Total hydrocarbon formation volume factor	Bbl/stb	vol/vol
B_{ti}	Initial total hydrocarbon formation volume factor	Bbl/stb	vol/vol

Symbols and Units - 2

c_o	Oil compressibility	psi^{-1}	bar^{-1}
c_p	Pore compressibility (c_f)	psi^{-1}	bar^{-1}
c_w	Water compressibility	psi^{-1}	bar^{-1}
P	Pressure	psi	bar
P_b	Bubble point pressure	psi	bar
P_i	Initial pressure	psi	bar
Rl	Liberated gas	scf/bbl	m^3/m^3
R_s	Solution gas at pressure P	scf/bbl	m^3/m^3
R_{si}	Initial gas in solution at P_i	scf/bbl	m^3/m^3

1 bbl = 5.615 cuft

1 bbl = 0.159 m^3

1 bar = 14.5 psi

P_{std} = 14.7 psia T_{std} = 60 °F

P_{std} = 1.01325 barsa T_{std} = 15 °C

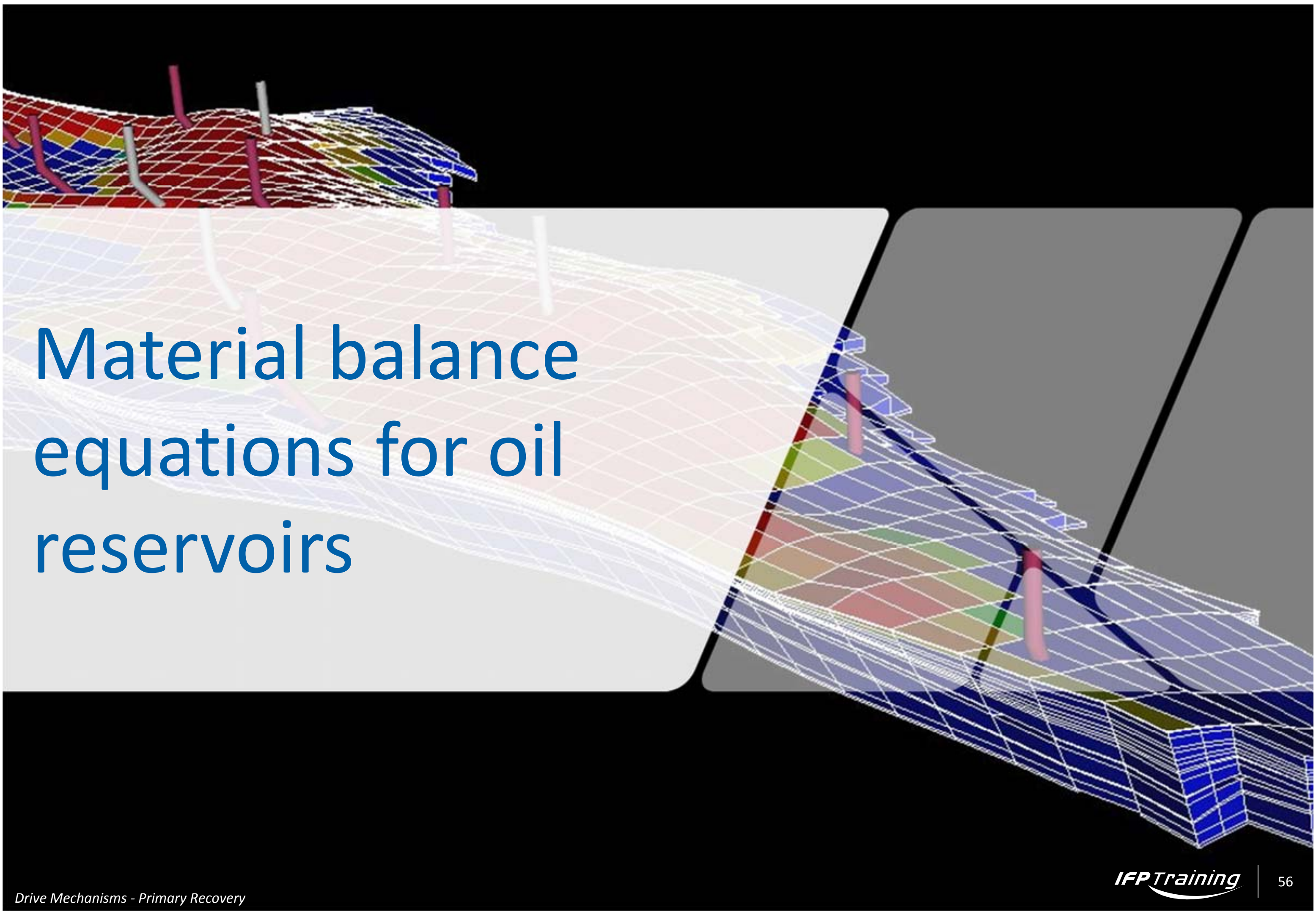
Principles of the material balance

- **The material balance expresses a conservation of the volumes of the fluids for the reservoir / part of reservoir for a finite time interval**
  - In order to be valid, a well established pressure regime shall exist in the reservoir or part of the reservoir under consideration

- **Since the accumulations and produced volumes are expressed in surface conditions we need to use fluid properties like the formation volume factor in order to convert from surface to reservoir conditions**

- **Compressibility effects are of great importance since they are the basis for volume conservation: oil expansion, gas expansion, connate water expansion and pore volume reduction (compaction)**

Note



Material balance equations for oil reservoirs

Material balance equations for oil reservoirs

Simplified MBE for undersaturated oil expansion

- **Considering that there is no aquifer activity (i.e. no water entry in the reservoir), no gas cap and no liberation of solution gas and disregarding the compressibility of the connate water and of the pore volume**
- **It can be stated that the volume occupied by the oil remains constant:**

  volume of expanded remaining oil = initial volume of oil

$$\left(N - N_p\right)B_o = NB_{oi}$$

$$Rf = N_P/N = 1 - B_{oi}/B_o$$

- **However water and pore volume compressibilities have to be taken into account to better estimate the recovery factor**
  - Water and pore volume compressibilities are generally of the same order of magnitude than oil compressibility

Detailed MBE for undersaturated oil expansion

- **Still considering that there is no water entry, no gas cap, no liberation of solution gas**

Produced volume = Increase of volume of oil (expansion)
+ Increase of volume of water (expansion)
+ Decrease of pore volume (compaction)

- **For a pressure drop ΔP from P_i to P with $P > P_b$ (undersaturated oil):**
  - Produced oil volume: $N_p \cdot B_o$
  - Increase in volume of oil: $(V_p \cdot S_o \cdot c_o) \cdot \Delta P$
  - Increase in volume of connate water: $(V_p \cdot S_{wi} \cdot c_w) \cdot \Delta P$
  - Decrease in pore volume: $(V_p \cdot c_p) \cdot \Delta P$

where V_p is the pore volume

$$N_p B_o = V_p \Delta P (c_o S_o + c_w S_{wi} + c_p)$$

Detailed MBE for undersaturated oil expansion and *Rf*

- **Introducing equivalent compressibility:**

$$c_e = (c_o S_o + c_w S_{wi} + c_p)/S_o = c_t/S_o$$

- **The material balance equation (MBE) writes:**

$$N_p B_o = c_e S_o V_p \Delta P$$

with $S_o V_p = N B_{oi}$

$$N_p B_o = N B_{oi} c_e \Delta P$$

$$Rf = N_P/N = \frac{B_{oi}}{B_o} c_e \Delta P$$

- **From this equation, compressibilities of oil, water and pore volume being generally pretty low, we can infer that the calculated recovery factor will be low, typically a few %.**

Relationship between c_o and B_o above bubble point

- **By definition, c_o is the fractional change in oil volume with a unit change in pressure.**
  - This can also be expressed as a function of the variation in B_o above bubble point

$$c_o = \frac{-1}{V} \cdot \frac{dV}{dP}$$

hence

$$c_0 = \frac{-1}{B_o} \cdot \frac{dB_o}{dP}$$

or

$$c_o = -[(B_o - B_{oi})/B_{oi}]/(P - P_i)$$

- **Hence, above the saturation pressure, c_o can be derived from the slope of the line $B_o(P)$**

Using the undersaturated oil expansion MBE

- **First use:**
  - Knowing N, ΔP and the fluid properties, estimate N_p and Rf
  - In general, $R_f < 5\%$ leading to a secondary recovery scheme (e.g. water injection)

- **Second use:**
  - Knowing $N_p$and Δp (from production history), calculate the accumulation N and compare to the previous estimate from volumetric studies
  - If N is found to increase over time, it means that actual pressure drop in the reservoir is lower than the measured one => we may suspect **a pressure support from an active aquifer** and the drive mechanism may be natural water drive
  - If N is found much lower than the estimate coming from volumetrics, it means that only one part of the reservoir is drained
    - Compartmentalization => we may think to an **additional development** (new wells)
    - Heterogeneities in permeability => possible reconnection of the missing accumulation (slow)

MBE for solution gas drive

- **Considering there is no water entry and no gas cap**
- **Solution gas drive**
  - Reservoir pressure drops below bubble point pressure and free solution gas is liberated in the reservoir
  - The main mechanism is expansion of the released solution gas
  - Therefore the expansion of connate water can be neglected because of the respective value of connate water compressibility and gas compressibility
  - Accordingly, the compaction of the pore volume can also be neglected => pore volume is considered to be constant
  - Therefore

oil volume + liberated gas volume = constant

  - At initial pressure $\boldsymbol{P_i}$ $(= \boldsymbol{Pb})$: $\boldsymbol{V_{oi}}$, $\boldsymbol{V_w}$ at current pressure $\boldsymbol{P}$: $\boldsymbol{V_{or}}$, $\boldsymbol{V_w}$, $\boldsymbol{V_{gf}}$

Hence

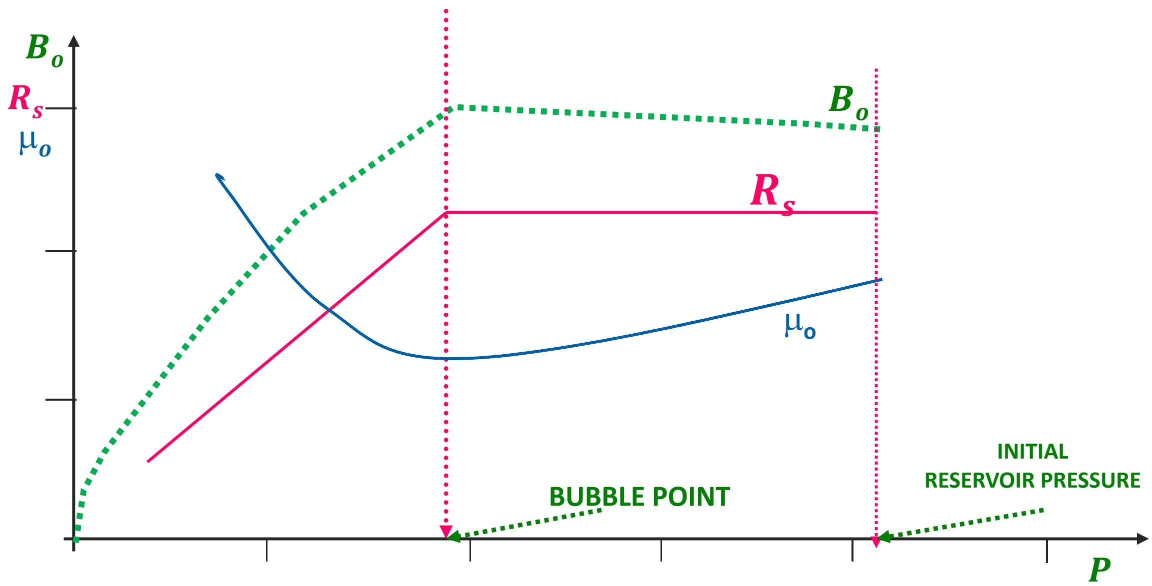
$$V_{oi} = V_{or} + V_{gf}$$

  - Finally introducing $\boldsymbol{R_S}$ the solution GOR and $\boldsymbol{B_g}$ the gas FVF, the final MBE is given by

$$NB_{oi} = (N - N_p)B_o + [NR_{si} - (N - N_p)R_s - G_p]B_g$$

PVT data reminder

- **Reminder of variation of main reservoir oil properties with pressure**



Material balance equations for oil reservoirs

MBE for solution gas drive and *Rf*

- **Introducing a new term in the previous equation: average GOR noted R_p**

$$R_P = G_p/N_p$$
$$G_P = R_p N_p$$

- **The MBE for solution gas drives can be expressed as:**

$$N_p\left[B_o + \left(R_p - R_s\right)B_g\right] = N\left[\left(B_o - B_{oi}\right) + \left(R_{si} - R_s\right)B_g\right]$$

oil production   free gas production   oil expansion   solution gas expansion

- **Therefore the recovery factor can be expressed as:**

$$Rf = N_p/N = \left[\left(B_o - B_{oi}\right) + \left(R_{si} - R_s\right)B_g\right]/\left[B_o + \left(R_p - R_s\right)B_g\right]$$

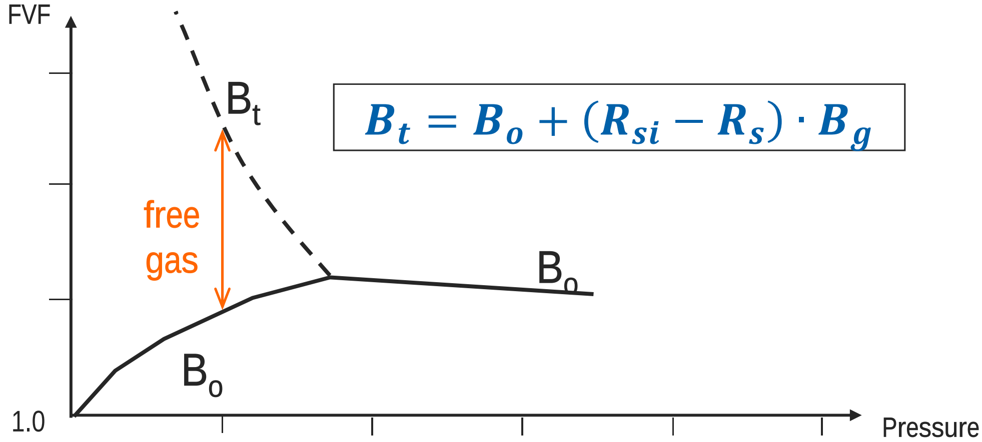
Hence $Rf = f\left(1/R_p\right)$: the recovery factor is a function of the **inverse of the average GOR**

- **MBE shows that as much gas as possible must be kept into the reservoir**
  - **Production flowrate should be low**

Material balance equations for oil reservoirs

Total formation volume factor and new MBE

- **Reminder about the variation of the FVF (Formation Volume Factor – B) with pressure**



$$\boxed{B_t = B_o + \left(R_{si} - R_s\right) \cdot B_g}$$

- **Introducing the total FVF in the solution gas drive MBE**

$$N_p\left[B_o + \left(R_p - R_s\right)B_g\right] = N\left(B_t - B_{ti}\right)$$
$$R_f = \left(B_t - B_{ti}\right)/\left[B_o + \left(R_p - R_s\right)B_g\right]$$

Material balance equations for oil reservoirs

MBE for gas cap drive

- **Still considering there is no water entry and neglecting the connate water and pore volume compressibilities**
- **Gas cap drive**
  - The main mechanism is the expansion of the gas cap that comes in addition to the expansion of the liberated solution gas
  - Hence, we add a term expressing the gas cap expansion to the solution gas drive MBE
  - Introducing the parameter m = Volume of gas zone / Volume of oil zone:

$$m = GB_{gi}/NB_{oi}$$

  - Therefore

$$G = mNB_{oi}/B_{gi} \quad @\mathrm{P_i} \qquad \text{and} \qquad GB_g = mNB_{oi}B_g/B_{gi} \quad @\mathrm{P} \ll \mathrm{P_i}$$

  - Hence the gas cap expansion is given by:

$$GB_g - GB_{gi} = mNB_{oi}B_g/B_{gi} - mNB_{oi} = mNB_{oi}(B_g/B_{gi} - 1)$$

  - Therefore the final MBE for the gas cap drive is:

$$N_p[B_o + (R_p - R_s)B_g] = N[(B_o - B_{oi}) + (R_{si} - R_s)B_g + mB_{oi}(B_g/B_{gi} - 1)]$$

oil production free gas production oil expansion solution gas expansion gas cap expansion

Material balance equations for oil reservoirs

MBE for gas cap drive – 2

- **The previous equation is quite complex and does not provide a clear picture of the principles involved in the gas-cap drive mechanism**
- **However, because of the gas-cap expansion, the pressure decline is less severe than for solution gas drive and oil recovery is greater**
- **If not neglecting water and pore compressibility, the final equation is:**

$$N_p[B_o + (R_p - R_s)B_g] = N\left[(B_o - B_{oi}) + (R_{si} - R_s)B_g + mB_{oi}(B_g/B_{gi} - 1) + (1+m)B_{oi}\left(\frac{c_w S_{wc} + c_p}{1 - S_{wc}}\right)\Delta P\right]$$

connate water expansion and pore volume compaction
within oil zone AND gas cap

MBE for natural water drive

- **Natural water drive implies water entry from the aquifer into the reservoir**
- **The corresponding volume of water has to be added to the corresponding equation without water drive**
- **Assuming undersaturated oil expansion (for sake of simplicity) and considering all fluids and pore volume compressibilities**

Oil production = Oil expansion + Connate water expansion + Pore volume compaction
+ Aquifer expansion => water entry W_e
- Water production => water production W_p

Therefore

$$N_p B_o = N B_{oi} c_e \Delta P + W_e - W_p B_w$$

- Assuming no water production, the recovery factor is:

$$Rf = N_p/N = \frac{B_{oi}}{B_o} c_e \Delta P + \frac{W_e}{N B_o}$$

- In any case, we need a **water influx model in order to calculate W_e**

Water influx models

- **Water influx models**
  - Pot aquifer model
  - Schilthuis steady-state model
  - Hurst modified steady-state model
  - Hurst and Van Everdingen unsteady state model
    - Radial edge-water drive
    - Radial bottom-water drive
    - Linear edge-water drive
  - Carter-Tracy unsteady-state model
  - Fetkovitch method
    - Radial aquifer
    - Linear aquifer
- **Water influx calculations are generally very uncertain since aquifer characteristics are poorly known and heavily rely on historical production data in order to indirectly estimate the aquifer characteristics**

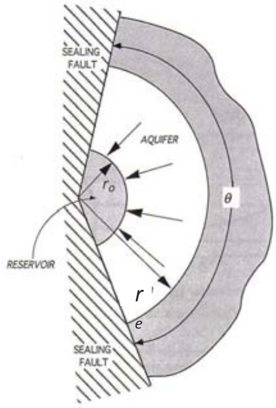
Water influx models

Pot aquifer model

- **Pot aquifer model = the simplest water influx model**
  - The pressure drop due to the production in the reservoir causes the aquifer to expand and the water to flow into the reservoir
  - Writing the corresponding MBE, we get:

$$W_e = W_i c_t \Delta P = W_i\left(c_w + c_f\right) \cdot f \cdot (P_i - P)$$

where W_i is the initial volume of water in the aquifer
c_t is the aquifer total compressibility
P_i is the initial aquifer/reservoir pressure
P is the current reservoir pressure (@WOC or @GWC)
f is the partial encroachment angle



  - This model is valid for small aquifers only (i.e. $r_e \approx r_o$) where the pressure drop at the aquifer/reservoir boundary transmits almost instantaneously through the entire aquifer
  - In the case of large aquifers, a **time dependent equation is needed**: the aquifer needs some time to react to the pressure change in the reservoir and to begin to produce inside the oil pool

Water influx models

Hurst & Van Everdingen unsteady-state model

- **The equation of water flowing from the aquifer into the reservoir is derived from the equation of oil flowing from reservoir into the well**
  - In the latter case, the solution in pressure writes:

$$P_D(t_D) = \frac{2\pi kh}{q\mu}\left(P - P_{wf}\right)$$

where $P_D(t_D)$ is the dimensionless pressure function corresponding to the CTR case

  - In the case of determining water influx, we are much interested in calculating the influx flow rate
  - Hurst and Van Everdingen solved the radial diffusivity equation for the reservoir-aquifer system and derived the constant terminal pressure (CTP) solution of form:

$$q_D(t_D) = \frac{q\mu}{2\pi kh\Delta P}$$

where $q_D(t_D)$ is the dimensionless influx rate evaluated at $r_D = 1$

  - $q_D(t_D)$ describes the change in rate from 0 to q due to a pressure drop ΔP applied at the outer reservoir boundary r_o at time $t = 0$

HVE model – Solution for edge-water drive

- **The solution is generally expressed in terms of cumulated influx by integrating previous equation**
- **Therefore HVE solution writes:**

$$\frac{\mu}{2\pi kh\Delta P}\int_0^t q\,dt = \int_0^{t_D} q_D(t_D)\frac{dt}{dt_D}dt_D \qquad \text{with} \quad t_D = \frac{k}{\Phi\mu c_t}\frac{t}{r_o{}^2}$$

$$\frac{\mu W_e}{2\pi kh\Delta P} = W_{eD}(t_D)\frac{\Phi\mu c_t r_o{}^2}{k}$$

where $W_{eD} = \int_0^{t_D} q_D(t_D)dt_D$ is the adimensional water entry

- **In general**

$$W_e = 2\pi f\Phi hc_t r_o{}^2\cdot\Delta P\cdot W_{eD}(t_D,r_{eD}) = U\cdot\Delta P\cdot W_{eD}(t_D,r_{eD})$$

where

$U = 2\pi f\Phi hc_t r_o{}^2$ is the **aquifer constant**

W_{eD} is **determined from tables** as a function of t_D and r_{eD}

HVE model – Solution for radial edge-water drive

- Aquifer constant

$U = 2\pi f\Phi hc_t r_o{}^2$ Darcy units (cc/atm)

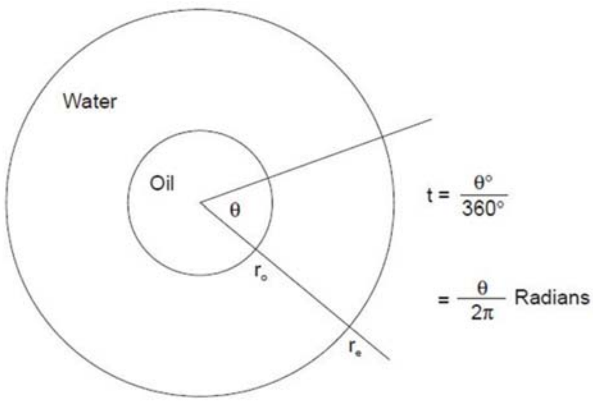
$U = 1.119 f\Phi hc_t r_o{}^2$ Field units (bbl/psi)

- Dimensionless time

$t_D = \frac{k}{\Phi\mu c_t}\frac{t}{r_o{}^2}$ Darcy units (t-seconds)

$t_D = c^{te}\frac{k}{\Phi\mu c_t}\frac{t}{r_o{}^2}$ Field units

With $c^{te} = 0.000264$ t-hours
$c^{te} = 0.006328$ t-days
$c^{te} = 2.309$ t-years



Water influx models

HVE model – Practical use

- **The former equation gives the expression of the water influx due to an instantaneous pressure drop at the reservoir/aquifer boundary**

- **In practice, we get a continuous pressure decline at the reservoir/aquifer boundary**
  - In this case, the continuous pressure decline is approximated by a series of discrete pressure steps $\Delta \boldsymbol{P_i}$
  - Then, for each pressure drop step, the corresponding water influx can be calculated by using the previous equation
  - The final cumulative water influx is given by superposition of each water influx, by respect to time

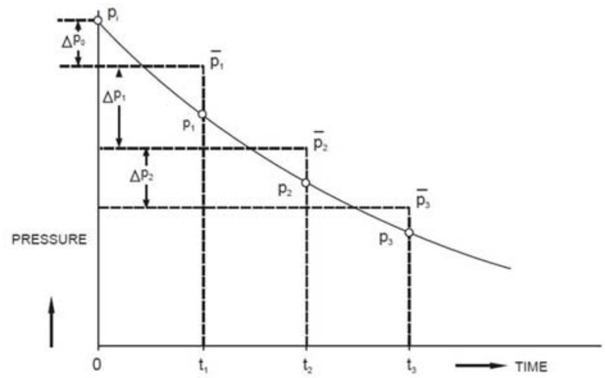
$$\boldsymbol{W_e(P_i, t) = U \sum_{i=1}^{n} W_{eD}(t_D, r_{eD}) \Delta P_i}$$

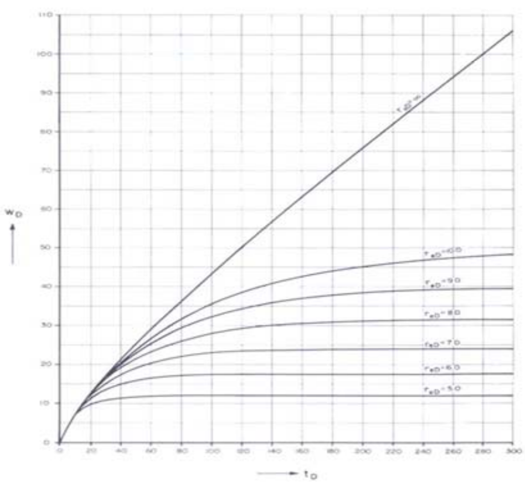
Water influx models

HVE model – Practical solving method

- **Solving HVE model procedure**
  - Calculate $\boldsymbol{r_{eD} = r_e / r_o}$ and $\boldsymbol{U}$
  - Discretize the pressure history
  - For each time step
    - For each pressure step
    - Calculate the corresponding value of adimensional time $\boldsymbol{t_D}$
    - Calculate the corresponding value of $\boldsymbol{W_{eD}}$ from the tables and/or curves
    - Sum up the contribution of each pressure drop and find the corresponding value of water entry $\boldsymbol{W_e}$

  => HVE method is an additive superposition process





Water influx models

HVE model – Solution for radial bottom-water drive

- **The HVE solution to the radial diffusivity equation is considered as the best aquifer model to date but it is not adapted to bottom-water drive since it cannot model vertical encroachments**
  - A model was derived by Coats (1962) taking into account vertical flows through a new parameter, **the permeability ratio**: $F_k = k_v/k_h$
  - A general solution was derived by Allard & Chen (1988) very much similar to the one of Hurst & Van Everdingen:

$$W_e = 2\pi\Phi h c_t {r_o}^2 \cdot \Delta P \cdot W_{eD}(t_D, z_D) = U \cdot \Delta P \cdot W_{eD}(t_D, r_{eD}, z_D)$$

where $z_D = \frac{h}{r_o\sqrt{F_k}}$ is the dimensionless vertical distance

  - The final solution is of the same nature:

$$W_e(P_i, t) = U \sum_{i=1}^{n} W_{eD}(t_D, r_{eD}, z_D)\Delta P_i$$

  - The values of adimensional water entry $W_{eD}(t_D, r_{eD}, z_D)$ are tabulated but they differ from the ones used for HVE solution for the edge-water drive

Water influx models

Carter-Tracy unsteady-state model

- **HVE model provides the exact solution to the radial diffusivity equation but the use of superposition principles involves quite tedious calculations**
- **Carter and Tracy proposed a technique (1960) allowing a direct calculation of the water influx**
  - The water flow rate is assumed constant over a finite time interval corresponding to a given pressure drop => the cumulative influx at time n can be calculated from the previous value at time $n-1$ using the equation:

$$W_e(t_{D,j}) = W_e(t_{D,j-1}) + \left(\frac{U\Delta p(t_{D,j}) - W_e(t_{D,j-1}) \cdot P'_D(t_{D,j})}{P_D(t_{D,j}) - t_{D,j-1} \cdot P'_D(t_{D,j})}\right) \cdot (t_{D,j} - t_{D,j-1})$$

Where U is the HVE water influx constant

$P_D(t_D)$ is the dimensionless solution of diffusivity equation with constant rate boundary condition

$P_D{}'(t_D) = dP_D(t_D)/dt_D$ is its time derivative

Water influx models

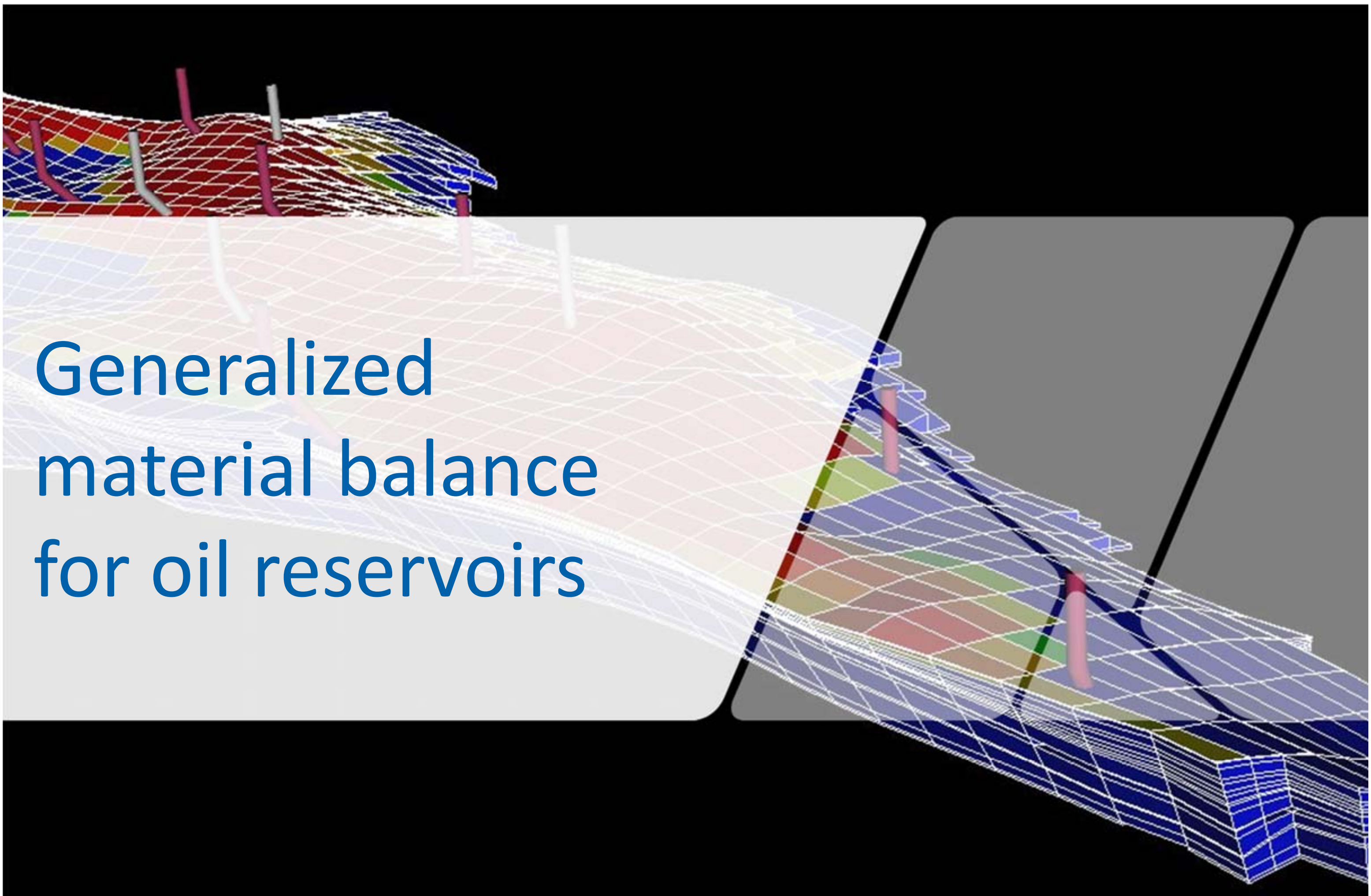
Solving Carter-Tracy model

- **Several possibilities:**
  - The $P_D(t_D)$ have been tabulated by Hurst and van Everdingen and can be used to directly compute $W_e(t_D)$ iteratively
  - If $t_D > 100$ the following expressions can be used:
    $P_D(t_D) = 0.5(\ln t_D + 0.80907)$
    $P_D{}'(t_D) = 1/(2 \cdot t_D)$
  - It is also possible to use the Fanchi's regression equation:
    $P_D(t_D) = a_0 + a_1 t_D + a_2 \ln t_D + a_3 (\ln t_D)^2$
    The values of the regression coefficients are given for different values of the ratio $r_{eD} = r_e / r_o$ (from Dake – The Practice of Reservoir Engineering)

r_{eD}	a_0	a_1	a_2	a_3
1.5	0.10371	1.66657	−0.04579	−0.01023
2.0	0.30210	0.68178	−0.01599	−0.01356
3.0	0.51243	0.29317	0.01534	−0.06732
4.0	0.63656	0.16101	0.15812	−0.09104
5.0	0.65106	0.10414	0.30953	−0.11258
6.0	0.63367	0.06940	0.41750	−0.11137
8.0	0.40132	0.04104	0.69592	−0.14350
10.0	0.14386	0.02649	0.89646	−0.15502
∞	0.82092	-3.68×10^{-4}	0.28908	0.02882

Material balance equations for oil reservoirs

- **From the material balance principle, equations can be written for each of the main natural drive mechanism**
  - These equations confirm the low recovery factor expected for the undersaturated oil expansion and the higher values for solution gas drive, gas cap drive and water drive
  - In the case of solution gas drive and gas cap drive, the MBE clearly shows that the gas must be kept as much as possible within the reservoir in order to get a high recovery
  - The natural water drive MBE needs water influx in order to predict recovery
  - Several models exist, the better being Hurst and Van Everdingen transient model
- **Using MBE can be two-folds**
  - It makes production forecast by calculating Rf between an initial and a final pressure
  - It uses production data to test hypotheses, typically the existence of an active aquifer
  - It uses production data to match the reservoir description parameters
    - Typically the aquifer parameters (especially the size), the size of the gas cap (through parameter m) and finally accumulation
    - Caution: MBE matches only connected accumulation



Generalized material balance for oil reservoirs

Generalized material balance for oil reservoirs

Most general MBE for oil reservoirs

- **Considering the following general case:**
  - A reservoir with an oil pool overlain by a gas-cap and underlain by an aquifer.
  - The oil pool is produced and the production at the surface will consist of oil, gas and water.
  - Initially, there is no injection of water or gas.

- **The most general MBE writes**

$$\boldsymbol{N_p\left[B_o + \left(R_p - R_s\right)B_g\right] = N\left[(B_o - B_{oi}) + (R_{si} - R_s)B_g + mB_{oi}\left(B_g/B_{gi} - 1\right) + (1+m)B_{oi}\left(\frac{c_w S_{wc} + c_p}{1 - S_{wc}}\right)\Delta P\right] + W_e - W_p B_w}$$

Drive index

- **Introducing**

$$D = N_p\left[B_o + \left(R_p - R_s\right)B_g\right] = N_p\left[B_t + \left(R_p - R_{si}\right)B_g\right]$$

and dividing by D we get:

$$1 = \frac{N\left[\left(B_o - B_{oi}\right) + \left(R_{si} - R_s\right)B_g\right]}{D} + \frac{mNB_{oi}\left[B_g/B_{gi} - 1\right]}{D}$$

$$+ \frac{(1+m)NB_{oi}}{D}\left(\frac{c_w S_{wc} + c_p}{1 - S_{wc}}\right)\Delta P + \frac{W_e - W_p B_w}{D}$$

$$1 = DDI + SDI + CDI + WDI$$

DDI	SDI	CDI	WDI
Depletion Drive Index	Segregation Drive Index	Formation / Connate Water Compressibility Drive Index	Water Drive Index

Interpretation of the drive index

- **In the previous equation:**
  - The numerators of the fractions represent:
    - the expansion of the initial oil zone (included released solution gas),
    - the expansion of the gas cap,
    - the compaction of the pore rock volume / expansion of connate water
    - the net water influx.
  - The denominator represents the volume of hydrocarbons produced, expressed at current reservoir pressure conditions
  - Each of the parameters *DDI*, *SDI*, *CDI* and *WDI*, characterizes one of the production mechanisms of the reservoir
    - Undersaturated oil expansion and solution gas drive
    - Compaction gas drive
    - Connate water expansion and compaction drive
    - Natural water drive
  - The evolution with time of the drive index will help identify the prominent drive mechanisms and make decisions for the future development

Generalized material balance for oil reservoirs

Injection drive index

- **In the case where there is a fluid injected within the reservoir**
  - Secondary recovery (see below)
  - Either water or gas or water and gas

- **In this case, a new additional drive index is added to MBE: Injection drive index**
  - Located in the right hand side of the previous equation

$$IDI = \frac{G_{inj}B_{ginj} + W_{inj}B_{winj}}{D}$$

  - Note that very often $B_{winj} = B_w$ but $B_{ginj} \neq B_g$ since the properties of the injected gas (after treatment) are different from the properties of the produced gas

Generalized material balance for oil reservoirs

Another expression of the generalized MBE

- **Another way to express the material balance is to state that**
  net total fluid withdrawal = expansion of the HC fluids in the reservoir
  + cumulative water influx

  - The net total volume of fluid withdrawal is given by:

$$F = N_p\left(B_o - R_sB_g\right) + B_g\left(G_p - G_{inj}\right) + B_w\left(W_p - W_{inj}\right)$$

  - The expansion of oil and its original dissolved gas is:

$$NE_o = N\left[(B_o - B_{oi}) + (R_{si} - R_s)B_g\right]$$

  - The expansion of the gas cap is

$$NmE_g = NmB_{oi}\left(B_g/B_{gi} - 1\right)$$

  - The pore volume compaction / connate water expansion is:

$$NE_{f,w} = N(1+m)B_{oi}\left(\frac{S_{wc}c_w + c_f}{1 - S_{wc}}\right)\Delta P$$

Another expression of the generalized MBE – 2

- **The new form generalized material balance equation writes:**

$$F = N\left(E_o + mE_g + E_{f,w}\right) + W_e$$

$$F = NE_t + W_e$$

Where:

$E_t = E_o + mE_g + E_{f,w}$ is the **total expansion factor**

$E_o = (B_o - B_{oi}) + (R_{si} - R_s)B_g$ is the **oil expansion factor**

$E_g = B_{oi}\left(B_g/B_{gi} - 1\right)$ is the **gas expansion factor**

$E_{f,w} = (1+m)B_{oi}\left(\frac{S_{wc} \cdot c_w + c_f}{1 - S_{wc}}\right)\Delta P$ is the **connate water expansion / PV compaction factor**

Material balance analysis - Havlena-Odeh method

- **In order to analyze the generalized MBE, Havlena and Odeh proposed a methodology that used plotting techniques to try to show a linear behavior from the equation**
  - Havlena D. & Odeh A. S., The Material Balance as an Equation of a Straight Line, Journal of Petroleum Technology, Aug. 1963

- **In the general case by plotting F as a function of $E_o + mE_g + E_{f,w}$ we may have a straight line of slope N and intercept W_e**

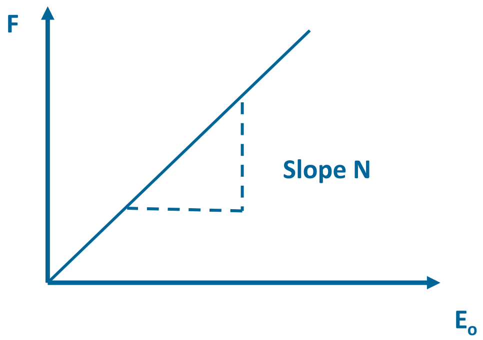
- **However, interpreting this plot can be quite difficult especially if N, m and the aquifer model are uncertain**

- **In most of the specific cases, the generalized MBE simplifies and may lead to simple plots**

Havlena-Odeh method – Solution gas drive

- **Assuming**
  - No gas cap and no aquifer
  - Pressure decreasing below bubble point pressure
  - Connate water and pore volume/rock compressibilities neglected

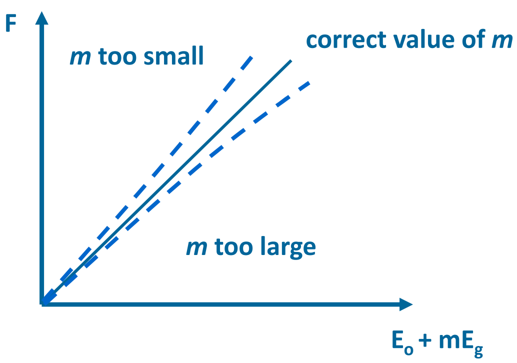
- **The generalized MBE writes:**
  - $F = NE_o$ => $F/E_o = N$
  - => by plotting $F = f(E_o)$ we may have a straight line of slope N



Havlena-Odeh method – Gas cap drive (1)

- **Assuming**
  - No aquifer
  - Pressure decreasing below bubble point pressure
  - Connate water and pore volume/rock compressibilities are neglected

- **The generalized MBE writes:**
  - $F = N(E_o + mE_g)$
  - => by plotting $F = f(E_o + mE_g)$ we may have a straight line of slope N

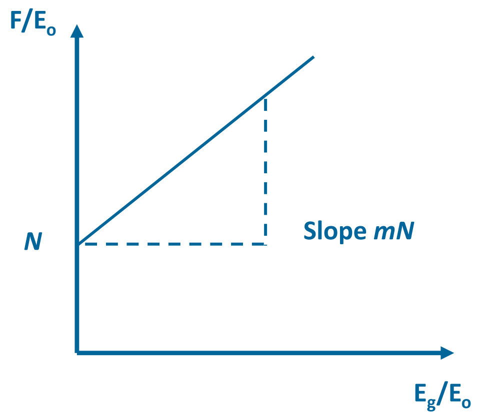


This plot can be used to check different hypotheses on the value of *m*

The correct value of *m* is obtained when the plot shows a straight line of slope *N* passing by the origin (assuming *N* is known)

Havlena-Odeh method – Gas cap drive (2)

- **Same assumptions**
- **The generalized MBE writes:**
  - $F = N(E_o + mE_g)$ => $F/E_o = N + mN\frac{E_g}{E_o}$
  - => by plotting $F/E_o = f(E_g/E_o)$ we may have a straight line of slope mN and intercept N



This plot can be used to check hypothess on *m* and *N*

When the plot shows a straight line, the intercept with the Y axis gives *N* and the slope gives *mN*

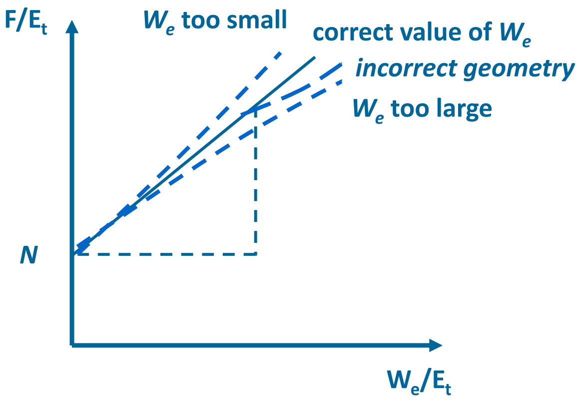
Havlena-Odeh method – Water drive

- **The generalized MBE writes:**

$F = NE_t + W_e$ => $F/E_t = N + W_e/E_t$ with $E_t = E_o + mE_g + E_{f,w}$

=> by plotting $F/E = f(W_e/E_t)$ we may have a straight line of slope 1 and intercept N

Note that E_t expression may simplify depending on the drive mechanisms to be considered



This plot is very useful to confirm the water influx model

Indeed, aquifers, even analytically, are characterized by various parameters: type, angle of encroachment, external radius, petrophysics etc. all uncertain

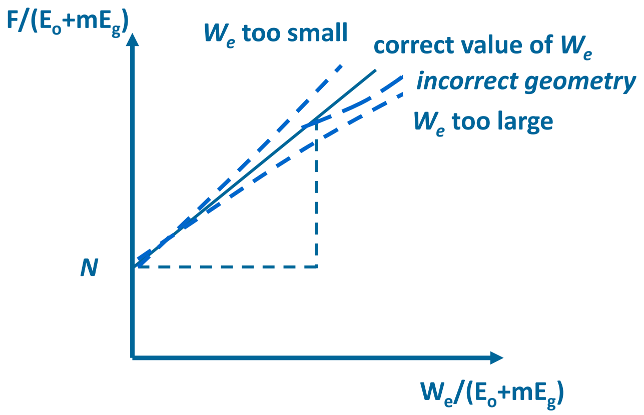
The appropriate aquifer model will show a straight line of slope 1 and intercept *N* ; any deviation is due to incorrect geometry or incorrect size of the aquifer

Havlena-Odeh method – Aquifer and gas cap

- **Assuming**
  - N and m are known
  - Connate water and rock compressibilities are neglected
- **The generalized MBE rewrites:**

$F = N(E_o + mE_g) + W_e$ => $F/(E_o + mE_g) = N + W_e/(E_o + mE_g)$

=> by plotting $F/(E_o + mE_g) = f(W_e/(E_o + mE_g))$ we may have a straight line of slope 1 and intercept N



This plot is used in the same way than the previous one in order to confirm the water influx model

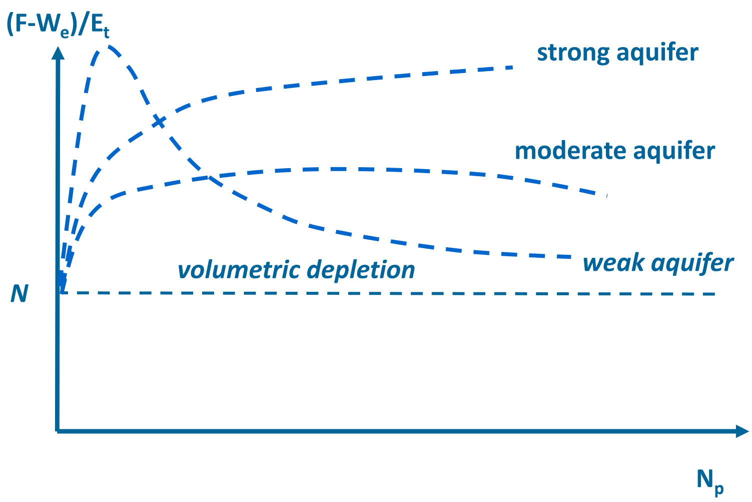
General case – Campbell plot

- **In the most general case, MBE writes:**

$F = N(E_o + mE_g + E_{f,w}) + W_e$

that is $F = NE_t + W_e$ => $(F - W_e)/E_t = N$

=> by plotting $(F - W_e)/E_t = f(N_p)$ we may have a straight line of slope 0 and intercept N i.e. of equation y = N



To have a good match, all the points should be on the line $y = N$; deviation from the horizontal line gives an indication on the way to modify the aquifer

The Campbell plot is widely used since it gives good feelings about the aquifer characteristics

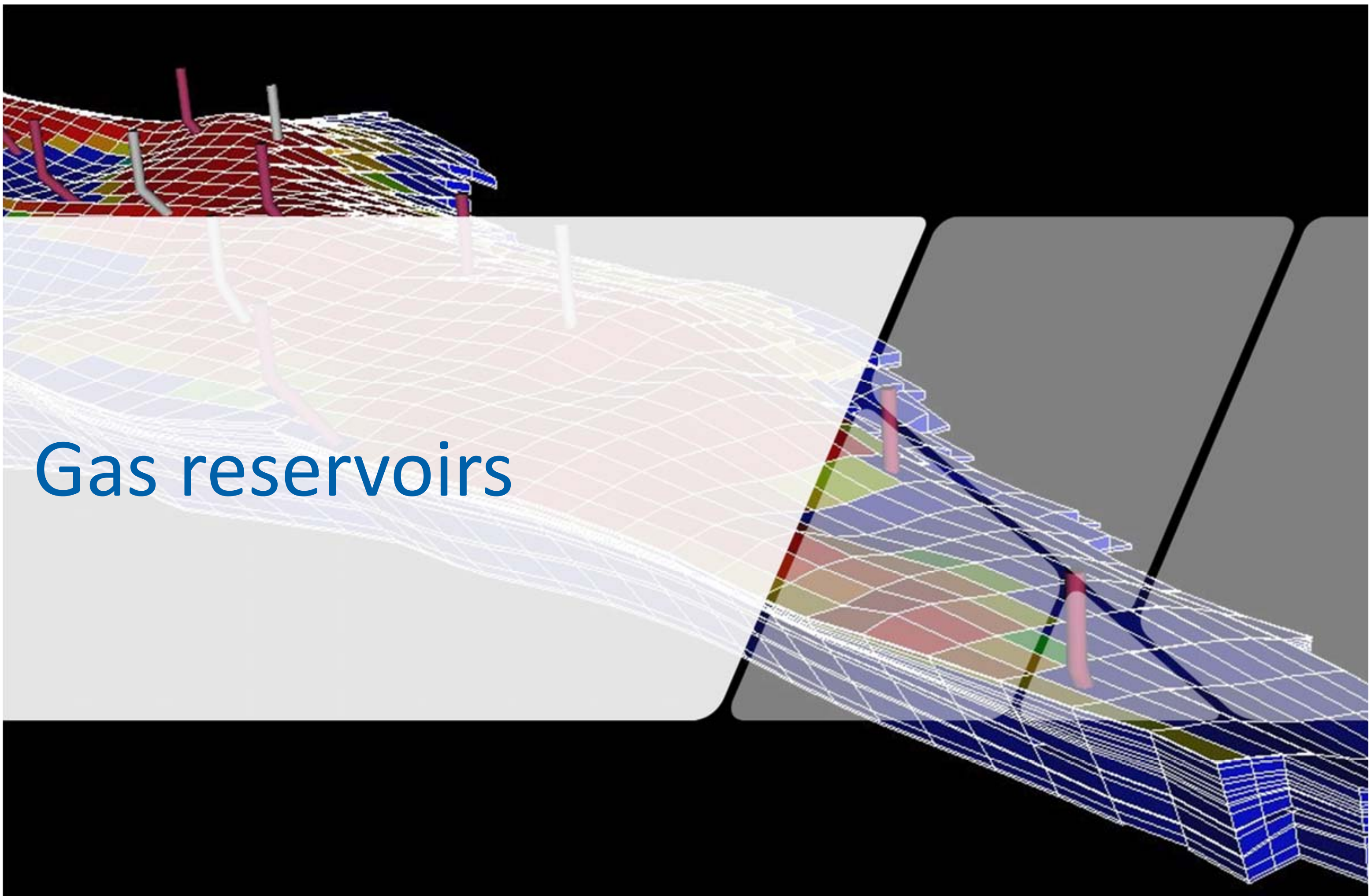
In general, the plot is built without any aquifer in the model to check which type of aquifer should be added:

- strong aquifer => constant pressure boundary
- moderate aquifer => infinite aquifer
- weak aquifer => no flow boundary
- no aquifer => volumetric depletion

Generalized material balance for oil reservoirs

- **Oil field generalized material balance equation is quite complex and difficult to solve in theory (finding *N*, *m* and the aquifer model parameters)**
- **Havlena and Odeh methodology proposes a simplified analysis based upon plotting and trying to find a linear behavior**
- **These plots allow to confirm the value of the original oil in place *N*; they also allow to check the presence of an active aquifer and, if any, to match the water influx model**
- **In the most general case, Campbell plot is widely used to check the presence of an active aquifer and to determine its characteristics**
- **The Drive Index is an additional method allowing to analyze the generalized MBE and to compare the relative importance of the various production mechanisms one to each other, thus providing a guide for further development of the field**

Note

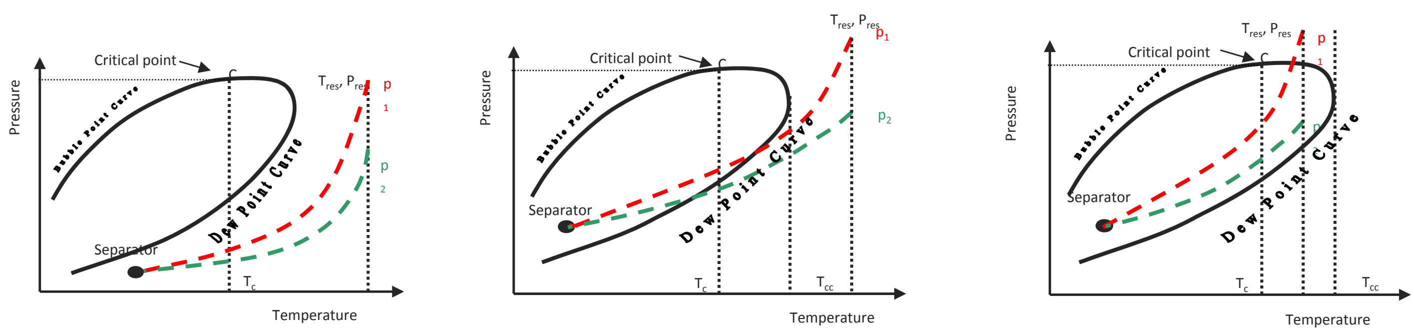


Gas reservoirs

Gas reservoirs

Reminder on gas reservoirs

- **Hydrocarbons are generally classified as either oil reservoir or gas reservoirs, depending on the state of the reservoir contents at discovery.**
  - For gas reservoirs, the different gas definitions refer to the PVT behavior of the gas, which depends on the initial reservoir gas composition, initial reservoir pressure and temperature.
- **A gas reservoir is a reservoir in which hydrocarbons remain in the gaseous state throughout the life of the reservoir.**
  - Dry gas or wet gas reservoirs
  - A reservoir in which part of the gas condensates in-situ is a gas condensate reservoir



Gas reservoir drive mechanisms

- **Gas reservoirs are produced mainly through monophasic natural depletion**

- **Gas compressibility is much higher than liquids/pore volume compressibilities**
  - We expect higher values of recovery factor than for oil reservoirs, **typically above 90%**
  - The lower the abandon pressure, the higher the recovery factor

- **Main concern of gas reservoirs: aquifer activity**
  - In case there is an active aquifer, the reservoir will be flooded by water
  - Despite the difference in mobility in favor of the gas, a significant part of the gas will be trapped by the water behind the front
  - We expect a much lower recovery factor than without aquifer activity, **typically in the range of 60-70%**
  - In this case, recommendation is to produce **as fast as possible** before flooding of the reservoir

MBE for gas reservoir without water entry

- **Assuming no water entry and neglecting connate water and pore volume compressibilities compared to gas compressibility**
- **When pressure drops, the volume occupied by the gas under reservoir conditions does not change i.e.**

initial gas accumulation = gas accumulation @(P,T)

$$GB_{gi} = (G - G_p)B_g$$

$$G_p = G(1 - B_{gi}/B_g)$$

Where

G is the initial accumulation of gas in standard conditions

G_p is the cumulative gas production in standard conditions

Reminders about equations of state (EOS)

- **Equations of state: $f(P,V,T,n) = 0$**
- **Ideal gas law (Mariotte, 1650):**

$$PV = nRT$$

- **Equation of state for real gas:**

$$PV = ZnRT$$

Where Z is the compressibility factor: a measurement of the difference in the real gas from the ideal gas ; when $\mathbf{P} \rightarrow \mathbf{1atm}$ then $\mathbf{Z} \rightarrow \mathbf{1}$

- **Cubic equations of state**
  - Van der Waals (1873) $P = RT/(V-b) - a/V^2$
  - Redlich-Kwong (1949) $P = RT/(V-b) - a/\left[V(V-b)T^{1/2}\right]$
  - Soave-Redlich-Kwong (1972) $P = RT/(V-b) - a(T)/[V(V+b)]$
  - Peng-Robinson (1976) $P = RT/(V-b) - a(T)/[V^2 + 2bV - b^2]$
  - Coefficients a and b are matched using PVT package typically from results coming from CVD experiments (cf. PVT studies)

Expansion factor and FVF

- **Gas expansion factor:**

$$E = 1/B_g$$

- **B_g is the gas FVF i.e. ratio of the volume of n moles of gas at reservoir conditions divided by the volume of n moles of gas at standard conditions**

@standard conditions: $P_0V_0 = Z_0nRT_0 = nRT_0$

@reservoir conditions: $PV = ZnRT$ => $B_g = Z \cdot P_o/P \cdot T/T_o$

@initial conditions: $P_iV_i = Z_inRT_i$ => $B_{gi} = Z_i \cdot P_o/P_i \cdot T_i/T_o$

- **Assuming that the reservoir temperature remains constant (isothermal transformation in the reservoir), we get:**

$$\frac{B_{gi}}{B_g} = \frac{Z_i}{P_i} \cdot \frac{P}{Z}$$

Recovery factor for gas reservoir without water entry

- **The recovery factor writes:**

$$Rf = G_p/G = 1 - B_{gi}/B_g = 1 - \frac{Z_i}{P_i} \times \frac{P}{Z}$$

- **Recovery is a function of:**
  - The original reservoir pressure
  - The current reservoir pressure
  - The gas mixture composition through Z (and Z_i)

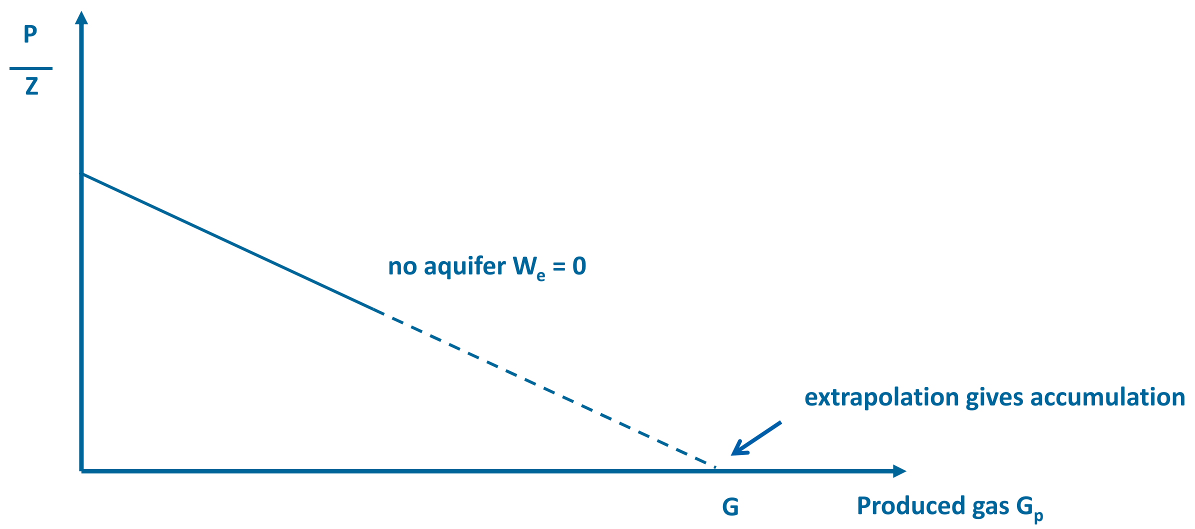
- **It is assumed that the reservoir depletes in the same manner everywhere i.e. the pressure rate decrease is the same everywhere in the reservoir**
  - Corresponding Rf can be very high, up to 90-95% (e.g. Lacq)

Typical behavior of gas reservoirs without aquifer

- **Analysis: plotting $P/Z = f(G_p)$**

$$\frac{P}{Z} = \frac{P_i}{Z_i}(1 - G_p/G)$$

  - it is a straight line for a closed reservoir (no water entry)
  - The extrapolation of the line gives the estimate of the accumulation G



Gas reservoirs

Overpressured reservoirs

- **For highly compressible reservoirs (overpressured), the combined effect of connate water and pore volume compressibility cannot be ignored at high initial pressures and the generalized MBE writes:**

$$G(1 - c_e \Delta P) B_{gi} = (G - G_p) B_g$$

Where $c_e = \frac{c_f + S_{wc} c_w}{1 - S_{wc}}$

- **The recovery factor writes**

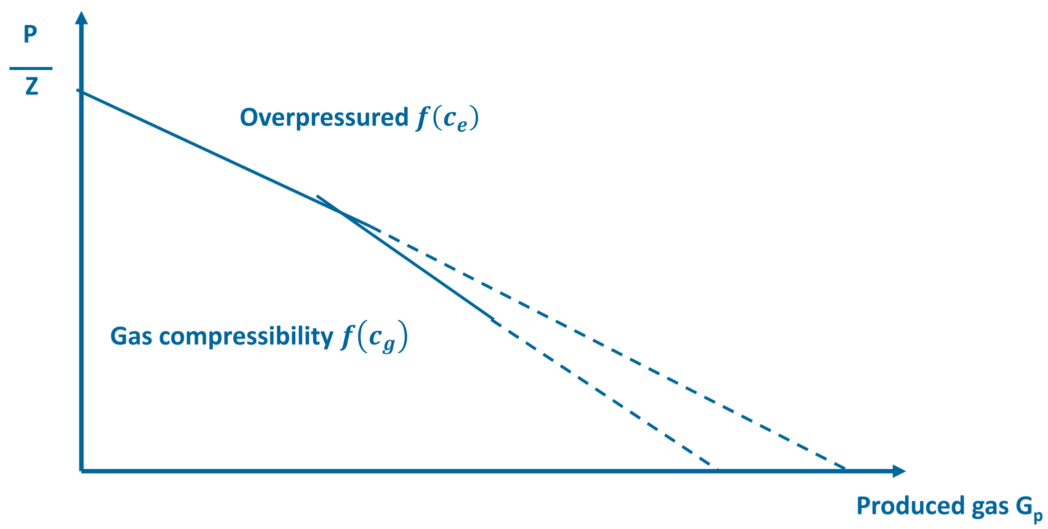
$$Rf = G_p/G = 1 - (1 - c_e \Delta P) B_{gi}/B_g = 1 - (1 - c_e \Delta P) \frac{Z_i}{P_i} \times \frac{P}{Z}$$

- **When the pressure in the reservoir decreases, the effect of c_e can be neglected again in front of c_g**
- **In this case, P/Z plot typically displays a change in the slope which can lead to very significant overestimate of the accumulation G**
  - A change in slope refers to a change in pore volume/rock compressibility when the pressure decreases but some overpressured gas reservoir does not show any slope change !!!

Gas reservoirs

Overpressured reservoirs - P/Z plot

- **Analysis: plotting $P/Z = f(G_p)$**
  - Two slopes
  - c_g dominates only when pressure decreases enough



MBE for gas reservoirs with water entry

- **Still neglecting connate water and formation compressibilities compared to gas compressibility, the generalized material balance equation writes:**

  net fluid withdrawal = expansion of the HC fluids in the reservoir
  + cumulative water influx

- **The net total volume of fluid withdrawal is given by:**

$$F = G_p B_g + W_p B_w$$

- **The expansion of gas is:**

$$GE_g = G\left(B_g - B_{gi}\right)$$

- **The generalized MBE for a gas reservoir with water entry is given by:**

$$F = GE_g + W_e$$

$$G_p B_g + W_p B_w = G\left(B_g - B_{gi}\right) + W_e$$

Rf for gas reservoirs with water entry

- **The recovery factor is given by:**

$$Rf = G_p/G = 1 - B_{gi}/B_g + 1/GB_g \cdot \left(W_e - W_p B_w\right)$$

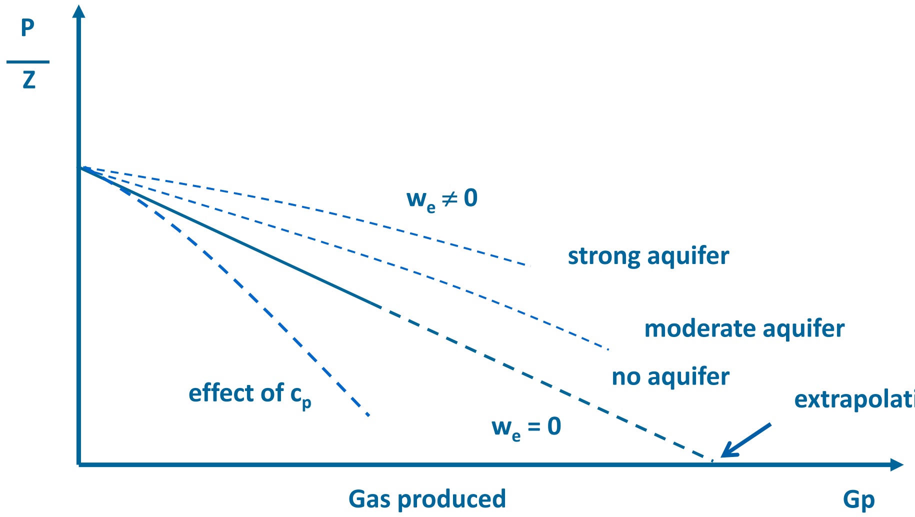
$$Rf = 1 - \frac{B_{gi}}{B_g}\left(1 - \frac{W_e - W_p B_w}{GB_{gi}}\right) = 1 - \left(1 - \frac{W_e - W_p B_w}{GB_{gi}}\right)\frac{P_i/Z_i}{P/Z}$$

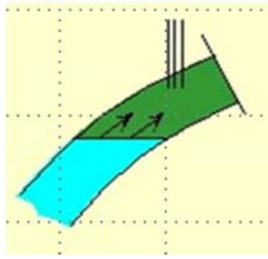
- **Recovery is a function of:**
  - The original reservoir pressure
  - The current reservoir pressure
  - The gas mixture composition
  - Water entries $\mathbf{W_e}$

- **The corresponding Rf is lower than without water entry because of the gas trapped behind the water front, ranging between 50% and 70%**

MBE analysis for gas reservoirs with water entry

- **Analysis: plotting $P/Z = f(G_p)$**
  - The straight line becomes exponential in case of an active aquifer
  - The estimate of gas accumulation by extrapolation of the line is no longer valid => actually, at the beginning of the reservoir life, the influence of the aquifer may still be weak and the extrapolation may be valid yet uncertain => need monitoring (observation wells, 4D seismic)





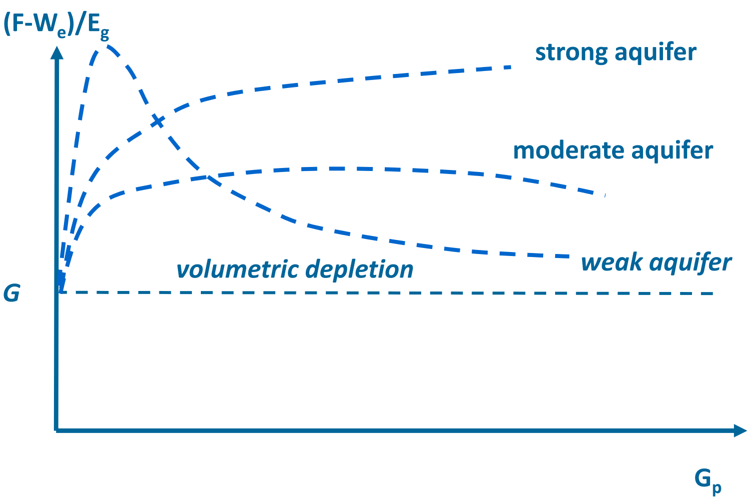
Havlenah-Odeh for gas reservoirs – Cole plot

- **The generalized MBE for a gas reservoir is given by:**

$$F = GE_g + W_e \quad \text{or} \quad F/E_g = G + W_e/E_g$$

where $F = G_pB_g + W_pB_w$ and $E_g = B_g - B_{gi}$

=> by plotting $(F - W_e)/E_g = f(G_p)$ we may have a straight line of slope 0 and intercept G i.e. of equation y = G



Cole plot is equivalent to Campbell plot for oil reservoirs.

Note that E_g should be replaced by E_t if water and pore volume compressibility are not neglected:

$$E_t = E_g + E_{f,w}$$

With

$$E_{f,w} = B_{gi}\left(\frac{S_{wc} \cdot c_w + c_f}{1 - S_{wc}}\right)\Delta P$$

Performance of a gas reservoir in case of water drive

- **In the case of natural water drive, the aim is to accelerate production in order to evacuate gas before water invades the reservoir and traps gas behind the front**

  - Typical mobility ratio for water-gas displacement:

$$M = \frac{k_{rwmaw}}{\mu_w} \Big/ \frac{k_{rgmaw}}{\mu_g} = \frac{0.2}{0.4} \Big/ \frac{1}{0.0.2} = 0.01$$

  - This value means that, for a given ΔP in the reservoir, the gas travels a hundred times faster than water => favorable case but however some gas may remain trapped

Assessment of the trapped gas volume

- **Trapped gas volume**

$$V_{trapped} = PV_{inv} \cdot S_{grw} \cdot 1/B_g$$

With PV_{inv} the pore volume invaded by water

And S_{grw} the residual gas saturation to water that depends on the properties of the porous media/fluids system, especially wettability and IFT

- **By definition**

$$W_e - W_p B_w = PV_{inv} \cdot \left(1 - S_{wc} - S_{grw}\right) = \alpha \cdot PV\left(1 - S_{wc} - S_{grw}\right) = \alpha \cdot MGV$$

With $PV = GB_{gi}/(1 - S_{wc})$ the **pore volume**

$MGV = PV\left(1 - S_{wc} - S_{grw}\right)$ the **movable gas volume**

α the **fractional volumetric sweep**

Therefore

$$V_{trapped} = \frac{W_e - W_p B_w}{1 - S_{wc} - S_{grw}} \cdot S_{grw} \cdot 1/B_g = \alpha \cdot G \cdot \frac{S_{grw}}{1 - S_{wc}} \cdot \frac{B_{gi}}{B_g}$$

Gas reservoirs
Performance at abandonment pressure

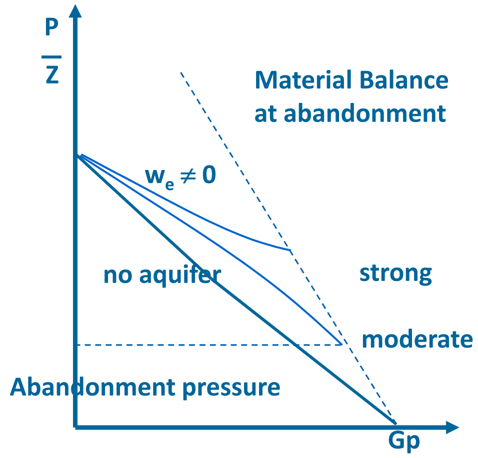
- **Production at abandonment pressure is given by the intersect of the material balance line and the P/Z plot**
  - Some of the gas will be trapped at S_{rgw} behind the front:

    $$\alpha G \frac{B_{gi}}{B_{gab}} \frac{S_{grw}}{1-S_{wc}}$$
  - Some of the gas will be by-passed by the water:

    $$(1-\alpha) G \frac{B_{gi}}{B_{gab}}$$
  - Finally:

$$G_{p,ab} = G - \alpha G \frac{B_{gi}}{B_{gab}} \frac{S_{grw}}{1-S_{wc}} - (1-\alpha) G \frac{B_{gi}}{B_{gab}}$$

$$\frac{P}{Z_{ab}} = \frac{P_i}{Z_i} \frac{\left(1-\frac{G_{p,ab}}{G}\right)}{\left(\frac{S_{grw}}{1-S_{wc}}+\frac{1-\alpha}{\alpha}\right)}$$



Gas reservoirs
Gas condensates reservoirs

- **Dry/Wet gas reservoirs**

$$G_p/G = 1 - \frac{Z_i}{P_i} \times \frac{P}{Z}$$

- **Condensates gas reservoir**
  - Above dew point pressure, the previous equation is still valid
  - Below dew point pressure, the liquids condensate in the reservoir and the previous equation has to be modified

$$G_p'/G = 1 - \frac{Z_i}{P_i} \times \frac{P}{Z_{2\,phases}}$$

Where $Z_{2\,phases}$ is the two-phase compressibility factor taking into account the presence of liquid in the reservoir ; it is determined through CVD experiment

And G_p' is the total production of hydrocarbons expressed in vapor phase:

$$G_p' = G_p + N_{p\,cond\,vap}$$

Gas reservoirs

Gas condensates reservoirs - 2

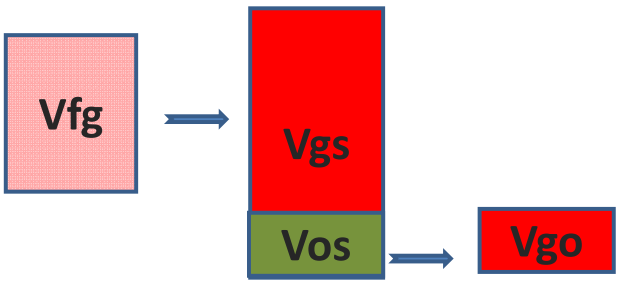
- **Total hydrocarbon production**

$$G_p' = G_p + N_{p\ cond\ vap}$$

$$N_{p\ cond\ vap} = N_p \rho_o * \frac{23.96}{M_w}$$

Where M_W is the molar weight: $M_w = \frac{6084}{°API - 5.9}$

And $°API = \frac{141.5}{d} - 131.5$



V_{fg} = gas volume in R.C

V_{gs} = gas volume at S.C.

V_{os} = condensates volume at S.C

V_{go} = volume of condensates expressed in vapor phase (nb moles *mole volume std) at S.C

$B_g' = V_{fg}/V_{gs} \quad B_g = V_{fg}/(V_{gs} + V_{go})$

Gas reservoirs

Gas condensates reservoirs – Condensate banking

- **Condensates banking**
  - Pressure drops mainly at the vicinity of the well
  - Hence, condensates will form first around the well where the pressure will first decrease below the dew point pressure => **condensate banking / blocking**
- **Possibly three zones in the reservoir**
  - Away from the producing wells, monophasic gas
  - Close to the producing wells: condensate build-up region but with monophasic flow still. Liquids drop out of gas but remain immobile because their saturation is below the critical saturation S_{cc}; it is supposed to be a constant volume depletion region.
  - Closest to the producing wells, both phases are flowing since the liquids saturation is above the critical saturation S_{cc}; it is supposed to be a constant composition depletion region
    - This region ranges from a few tens of feet for lean gas to hundreds of feet for rich gas
    - The size is proportional to the volume of gas drained and to the percentage of liquid drop out (CGR)
    - It also depends on permeability => more permeability leads to more gas produced, and leads to more extent of the zone
  - Capillarity may play a role by retaining condensates up to a high values of saturation

Gas condensates reservoirs – Condensate banking

Managing condensates banking

- Liquids should be of higher value than gas => the objective is to avoid condensates banking since part of the liquid will remain in the reservoir
- Furthermore, condensate blocking disturb the production of gas

Solutions

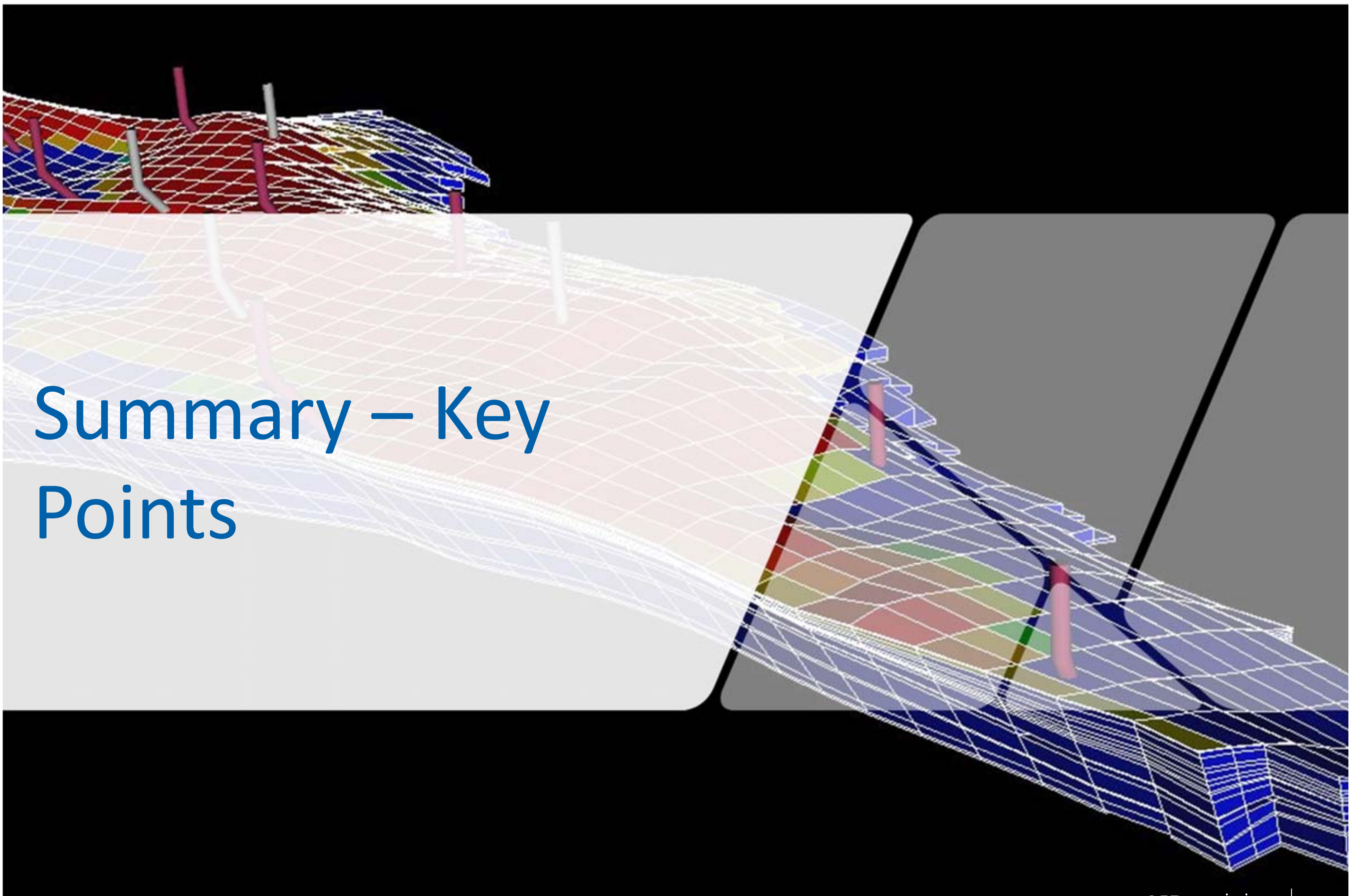
- **Gas cycling**: maintaining pressure over dew point by injecting gas, N_2 or CO_2 or dry gas
  - Finally dry gas (lean gas) may be produced at low bottom hole pressure
  - Economics: depends on the composition of the fluid and the quantity of liquids, on the availability of pipes to export the gas and on the liquid/gas prices
  - May be a seasonal activity or limited in time!
- Limiting pressure draw-down in the reservoir
- Increasing the contact area with the formation to increase production
  - Fracturing the reservoir (siliclastics) or acidizing the reservoir (carbonates) but condensates may form rapidly around fractures when sandface pressure drops below dew point pressure
  - Drill deviated/horizontal wells: longer time for the condensates to build up
- Remobilizing the liquids
  - By injecting solvents but costly (product, monitoring, etc.)

Dry gas/wet gas reservoir

- Without water entry and neglecting water and pore volume compressibility
  - Reservoir is produced through gas expansion only
  - $\boldsymbol{Rf}$ is a linear function of $\boldsymbol{P/Z}$ and can reach very high values, typically 90-95%
- With water entry
  - Despite a favorable mobility ratio, gas may be trapped behind the water front
  - $\boldsymbol{Rf}$ is still a function of $\boldsymbol{P/Z}$ but no longer linear and will be lower than without water entry, typically down to 50-70%

Gas condensates reservoir

- Above dew point pressure, it behaves like a dry gas/wet gas reservoir
- Below dew point pressure
  - Need to use 2-phase compressibility factor to take the liquid into account in the reservoir
  - $\boldsymbol{Rf}$ will be lower for both liquid and gas because of the diphasic flow and the decrease in k_r
  - Additionally, condensates banking: liquids will not flow until the critical saturation is reached
  - One solution may be gas recycling to maintain the pressure above dew point pressure



Summary – Key Points

Monophasic fluid expansion and pore volume reduction

- **It occurs when one phase only is mobile in the reservoir:**
  - Undersaturated oil reservoirs as well as gas and gas-condensate reservoirs (above dew point) produce by fluid expansion and pore volume reduction.

- **Reservoir performance:**
  - In undersaturated oil reservoirs, pressure declines very quickly; GOR remains constant until reservoir pressure falls below bubble-point pressure whenever GOR increases sharply (cf. solution gas drive); **R_f is very low, typically a few %**
  - In gas reservoirs, recoveries reach high value due to the combination of two specific gas characteristics, low viscosity and high compressibility; **R_f is very high, typically ranging 90-95%**

Oil reservoirs – Solution gas drive

- **The solution gas drive mechanism describes oil displacement by the expansion of gas released from solution as pressure is reduced below bubble point:**
  - As oil and gas production goes on, pressure declines further, more gas is released from solution.
  - Gas flow increases, oil flow decreases, as a result of the increasing gas saturation in the reservoir and of the unfavorable relative permeability evolution.

- **Reservoir performance:**
  - Solution gas drive reservoirs exhibit typically strong reservoir pressure decline and correspondingly rapid oil production decline.
  - $\boldsymbol{GOR}$ rises quickly from initial value to a maximum value, before declining rapidly.
  - Oil recovery is generally rather low, **typically ranging from 5 to 25 %**

Oil reservoirs – Gas cap drive

- **In presence of a gas cap above an oil zone, the pressure decline associated with the oil production will allow the gas cap to expand and provide additional energy to increase oil production**
  - To be effective, a large gas cap is necessary (initial or secondary gas cap).
  - For a secondary gas cap to form, high vertical permeabilities associated with a relatively homogeneous reservoir are needed.

- **Reservoir performance:**
  - An efficient gas cap drive mechanism exhibits typically a slower reservoir pressure decline and correspondingly a slower oil production decline than solution gas drive;
  - $\boldsymbol{GOR}$ rises slowly and progressively.
  - Oil recovery is generally higher than for solution gas drive reservoirs and it highly depends upon the vertical permeabilities.
  - **$\boldsymbol{Rf}$ typically ranges from 20 to 40%**

Oil reservoirs – Natural water drive

- **For a water drive reservoir, the pressure primary source of energy is supplied by water influx (from an adjacent aquifer) into the reservoir.**
  - In most cases, the energy for this water movement comes from water volume expansion and from the pore volume shrinkage in the aquifer.
- **Reservoir performance:**
  - Water drive effectiveness is a function of the aquifer properties and not the reservoir ones.
  - The two key parameters are the **aquifer size** and the **aquifer transmissibility**
  - The total fluid rate may remain constant, and if reservoir pressure is kept above bubble-point, GOR remains constant. On the other hand, the reservoir shows a steady increase in WOR.
  - A model to estimate the water entries is needed, especially for large aquifers (e.g. Hurst and Van Everdingen model)
  - **Oil recovery is high, typically ranging from 30 to 60 %**

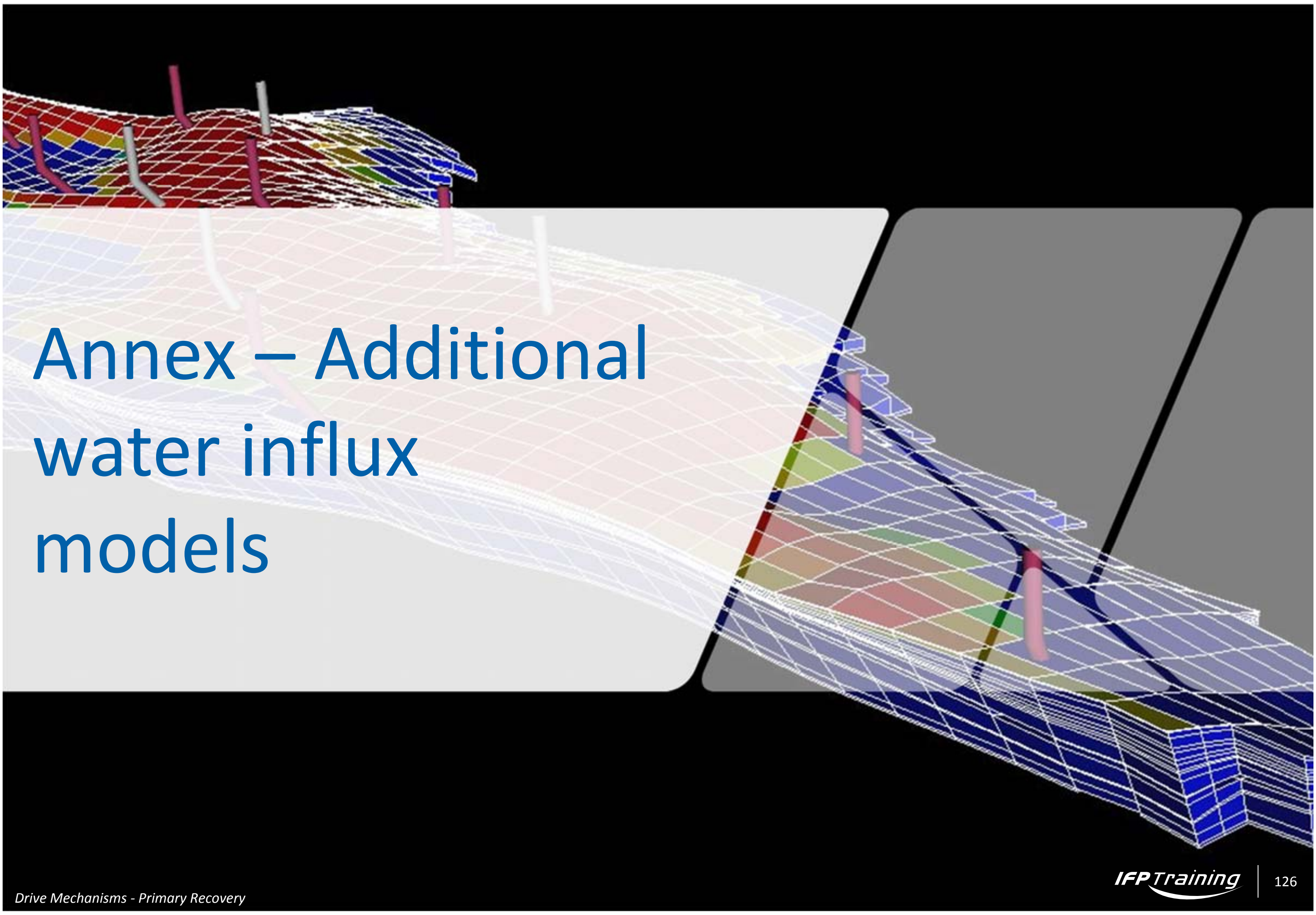
Gas reservoirs

- **For a gas reservoir, the gas compressibility becomes dominant and is a very significant drive mechanism.**
- **Reservoir performance:**
  - In the absence of an active aquifer, high recoveries can be achieved, **up to 90 %.**
  - In presence of an active aquifer, the risk of trapping gas lead to lower recoveries, Rf **may be as low as 60-70%**
    - Produce as fast as possible
    - Observation wells needed to monitor the water rise.
    - Evaluate $\mathbf{S_{grw}}$ (log - core)

Material Balance

- **The material balance is a basic tool for reservoir engineers to:**
  - Check production data consistency
  - Check the consistency between the geological evaluation and the reservoir behavior
  - Understand the reservoir behavior
  - Design a future complementary development plan
  - Perform production forecast

Note



Annex – Additional water influx models

Water influx models

Schilthuis steady-state model

- **Schilthuis model assumes that, under steady state conditions, the aquifer flow can be described by Darcy's equation**
- **Hence the rate of water influx can be expressed as:**

$$\boldsymbol{e_w = dW_e/dt = \frac{0.00708\,kh}{\mu_w \ln(r_e/r_o)} \cdot (p_i - p) = C \cdot (p_i - p)}$$

where $\boldsymbol{e_w}$ is the rate of water influx in bbl/d

$\boldsymbol{k}$ is the aquifer permeability in mD

$\boldsymbol{h}$ is the aquifer thickness in ft

$\boldsymbol{r_e}$ is the aquifer radius in ft

$\boldsymbol{r_o}$ is the reservoir radius in ft

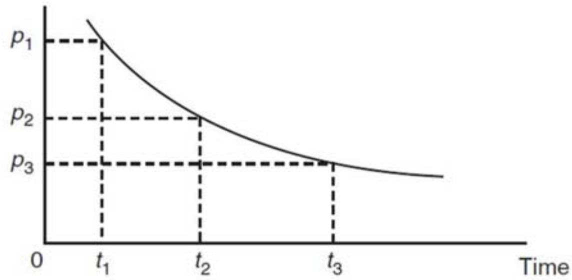
$\boldsymbol{C}$ is the water influx constant and can be calculated from the production history data provided that $\boldsymbol{e_w}$ is calculated independently

Water influx models

Schilthuis steady-state model - Solution

- **From previous equation, it can be seen that**
  - $W_e = C\int_0^t (p_i - p)dt$
  - The solution can be calculated by integrating $p_i - p$ as a function of time, for instance through graphical methods (area calculation) or any other integral approximation (trapezoid)
  - $\int_0^t (p_i - p)dt = \frac{p_i - p_1}{2} \cdot t_1 + \frac{(p_i - p_1)+(p_i - p_2)}{2} \cdot (t_2 - t_1) + \frac{(p_i - p_2)+(p_i - p_3)}{2} \cdot (t_3 - t_2) + \ldots$
- **The cumulative water influx can be approximated by:**

  $W_e = C\sum_0^t \Delta p \cdot \Delta t$



Water influx models

Hurst modified steady-state model

- **One limitation of Schilthuis model comes from the aquifer radius**
  - Indeed, the aquifer drainage radius increases with time
  - Hurst proposed to introduce a time-dependent dimensionless radius

$$r_{eD} = r_e/r_o = at$$

  - The corresponding modified water influx rate equation writes:

$$e_w = dW_e/dt = \frac{0.00708\, kh}{\mu_w \ln(at)} \cdot (p_i - p) = C \cdot \frac{(p_i - p)}{\ln(at)}$$

  - Therefore

$$W_e = C\int_0^t \frac{(p_i - p)}{\ln(at)}\, dt$$

  - Which can be approximated as:

$$W_e = C\sum_0^t \left[\frac{\Delta p}{\ln(at)}\right] \cdot \Delta t$$

Solving Hurst modified steady-state model

- **Hurst modified steady-state model has two unknown values: C and a**
- **They are estimated from reservoir/aquifer pressure history and from water influx rate history:**

$$\frac{p_i - p}{e_w} = \frac{1}{C}\ln(at) = \frac{1}{C}\ln a + \frac{1}{C}\ln t$$

- Plotting $(p_i - p)/e_w$ as a function of $\ln t$ should give a straight line of slope $1/C$ and intercept $1/C \cdot \ln a$
- However, this method requires to get independent estimates of e_w as a function of time

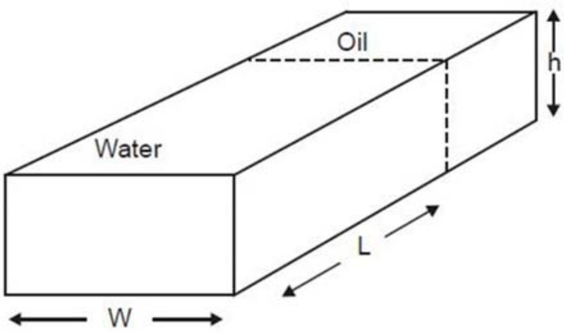
Water influx models

HVE model – Solution for edge-water drive linear aquifer

- Aquifer constant

$U = wLh\Phi c_t$ Darcy units (cc/atm)

$U = 0.1781 wLh\Phi c_t$ Field units (bbl/psi)



- Dimensionless time

$t_D = \frac{k}{\Phi \mu c_t}\frac{t}{L^2}$ Darcy units (t-seconds)

$t_D = c^{te}\frac{k}{\Phi \mu c_t}\frac{t}{L^2}$ Field units

with $c^{te} = 0.000264$ t-hours
$c^{te} = 0.00634$ t-days
$c^{te} = 2.309$ t-years

Note that t_D is now a function of the size of the aquifer

HVE model – Bounded aquifers

- **For bounded aquifers, it can be shown that W_D reaches a constant maximum value**

  - Radial aquifer: $W_{eD}(max) = 0.5(r_{eD}{}^2 - 1)$

  In this case and for a 360° aquifer, it can be shown that:

  $$W_e = \pi(r_e{}^2 - r_o{}^2)h\emptyset c_t \Delta p = W_i c_t \Delta p$$

  We find back the small pot model i.e. the total influx of water assuming the pressure drop Δp has been transmitted instantaneously throughout the aquifer

  - Linear aquifer: $W_{eD}(max) = 1$

HVE model – Infinite aquifers

- **No maximum value of W_{eD} can be reached since the water influx is always under transient conditions**
  - Radial aquifers with water-edge drive: Edwardson & al. (1962) developed 3 sets of simple polynomial expressions for calculating W_{eD} :
    - For $t_D < 0.01$ $\quad W_{eD} = \sqrt{t_D/\pi}$
    - For $0.01 < t_D < 200$ $\quad W_{eD} = \frac{1.2838\sqrt{t_D}+1.9328t_D+0.269872t_D{}^{3/2}+0.00855294t_D{}^2}{1+0.616599\sqrt{t_D}+0.0413008t_D}$
    - For $t_D > 200$ $\quad W_{eD} = (-4.29881 + 2.02566t_D)/\ln t_D$
  - Linear aquifer: it is possible to calculate the water influx directly

    $W_e = 2hw\sqrt{\emptyset k c_t t/\pi\mu} \times \Delta p$ in Darcy units (cc/s)

    $W_e = 0.00326hw\sqrt{\emptyset k c_t t/\pi\mu} \times \Delta p$ in Field units (bbl)

Water influx models

Fetkovitch method – Approximated HVE model

- **Principles:**
  - Introduced in 1971 in order to simplify the calculation of HVE model
  - The flow of water from the aquifer into the reservoir is modeled the same way as the flow of oil from the reservoir into the well:

$$q_w = \frac{dW_e}{dt} = J(\bar{p}_a - p)$$

where: q_w is the **water influx rate**

J is the **aquifer productivity index**

p is the **reservoir pressure** i.e. the pressure at the WOC (or GWC)

$\bar{p}_a$ is the **aquifer average pressure**

  - Average pressure in the aquifer is defined as:

$$W_e = \bar{c}V_w(p_i - \bar{p}_a)$$

where p_i is the initial pressure in the aquifer AND the reservoir that is

$$\bar{p}_a = p_i\left(1 - \frac{W_e}{c_t W_i p_i}\right) = p_i\left(1 - \frac{W_e}{W_{ei}}\right)$$

with $W_{ei} = c_t W_i p_i$ is the initial amount of encroachable water

Water drive

Fetkovitch method - Solution

- **After various steps of differentiation/integration we get:**

$$W_e = \frac{W_{ei}}{p_i}(p_i - p) \cdot \left(1 - e^{-Jp_i t/W_{ei}}\right)$$

When $t \to \infty$ then $W_e \to \frac{W_{ei}}{p_i}(p_i - p) = c_t W_i (p_i - p)$

That is the maximum value of water influx that can occur once the pressure drop $p_i - p$ has been transmitted to the whole aquifer

- **Practical use of Fetkovitch method**
  - The previous solution is only valid for a constant inner boundary pressure and we still shall need to use superposition theorem in order to use it
  - However Fetkovitch showed that superposition could be avoided using a different form of the previous equation

Water influx models

Fetkovitch method – Practical solving method

- **Methodology**
  - During the first time step Δt_1 we get:

$$\Delta W_{e_1} = \frac{W_{ei}}{p_i}(p_i - \overline{p}_1)\cdot\left(1 - e^{-Jp_i\Delta t_1/W_{ei}}\right)$$

where $\overline{p}_1$ is the average reservoir boundary pressure during the first time step

  - During the second time step Δt_2 we get:

$$\Delta W_{e_2} = \frac{W_{ei}}{p_i}(\overline{p}_{a_1} - \overline{p}_2)\cdot\left(1 - e^{-Jp_i\Delta t_2/W_{ei}}\right)$$

where $\overline{p}_{a_1} = p_i\left(1 - \frac{\Delta W_{e1}}{W_{ei}}\right)$ is the average aquifer pressure during the first time step

and $\overline{p}_2$ is the average reservoir boundary pressure during the 2nd time step

  - In general, for the nth time period we get:

$$\Delta W_{e_n} = \frac{W_{ei}}{p_i}(\overline{p}_{a_{n-1}} - \overline{p}_n)\cdot\left(1 - e^{-Jp_i\Delta t_n/W_{ei}}\right)$$

where $\overline{p}_{a_{n-1}} = p_i\left(1 - \frac{\sum_{j=1}^{n-1}\Delta W_{e_j}}{W_{ei}}\right)$ is the average aquifer pressure during the n-1th time step

and $\overline{p}_n$ is the average reservoir boundary pressure during the nth time step

Water influx models

Fetkovitch method – Aquifer productivity index

- **In order to be solved, Fetkovitch method requires that the aquifer productivity index J is calculated**
- **Pseudo-steady state with $\Delta P = p_i - \overline{p}_a$**
  - Radial aquifer

$J = \frac{fkh}{\mu\left(\ln\frac{r_e}{r_o} - 0.75\right)}$ Darcy units (cc/s/atm)

$J = 0.00708\,\frac{fkh}{\mu\left(\ln\frac{r_e}{r_o} - 0.75\right)}$ Field units (b/d/psi)

  - Linear aquifer

$J = 3\,\frac{khw}{\mu L}$ Darcy units (cc/s/atm)

$J = 3.381\,\frac{khw}{\mu L}$ Field units (b/d/psi)

Fetkovitch method – Limitations

- **Small aquifers**
  - The expression of aquifer productivity index J used in Fetkovitch modeling is valid only if $(r_o/r_e)^2$ is negligible

  => this can be untrue for small radial aquifers but Fetkovich approximate showed robust behavior to this assumption

- **Large aquifers**
  - The initial influx of water is under transient flow conditions and the corresponding expression of aquifer productivity index J is no longer valid

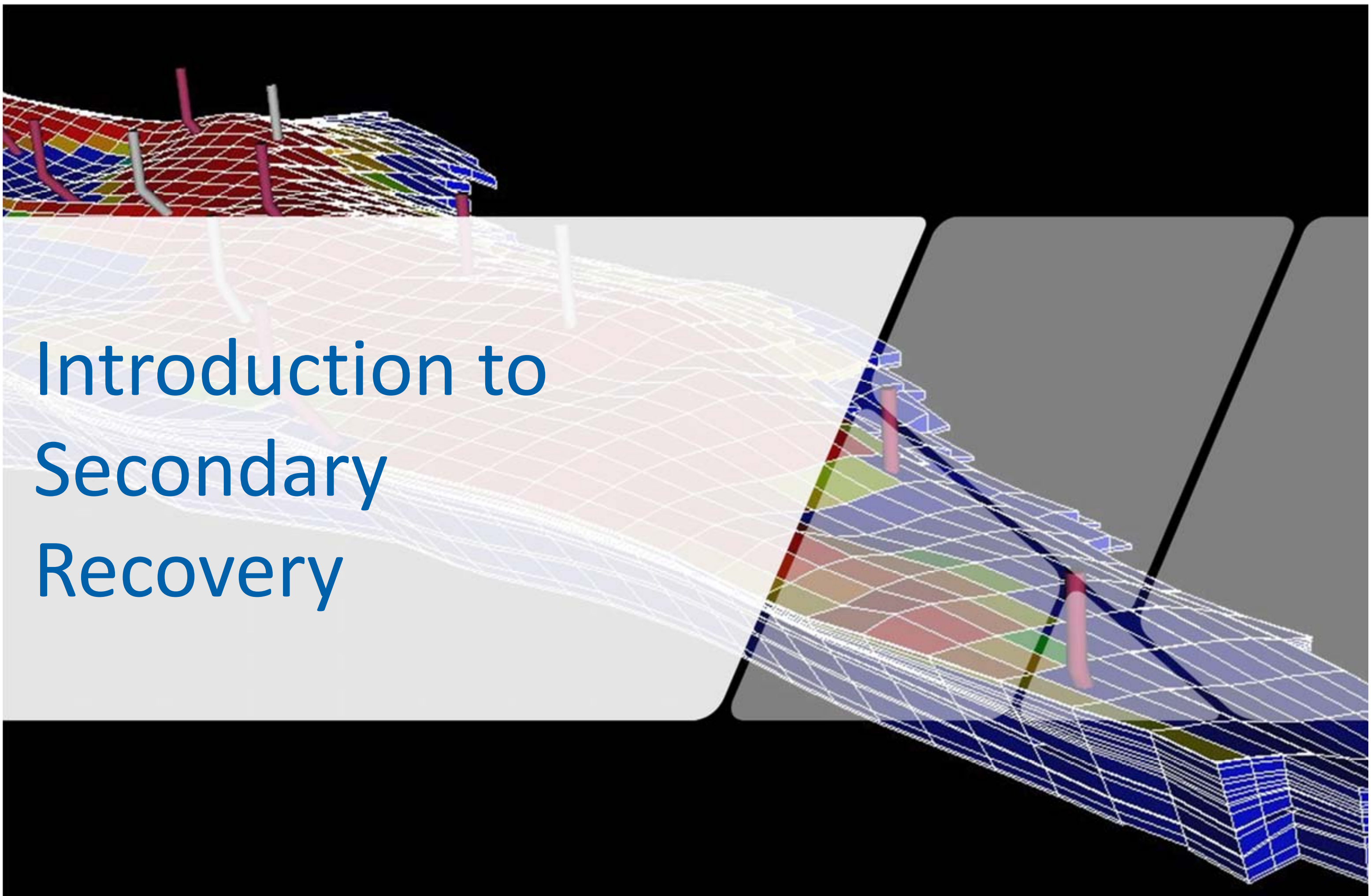
  => **Fetkovich method cannot model infinite aquifers**

  => for very large aquifers, it is still necessary to use the HVE method at early times

Drive mechanisms
Secondary recovery

IFP Training

Contents



Introduction to Secondary Recovery

Introduction to secondary recovery

Principles

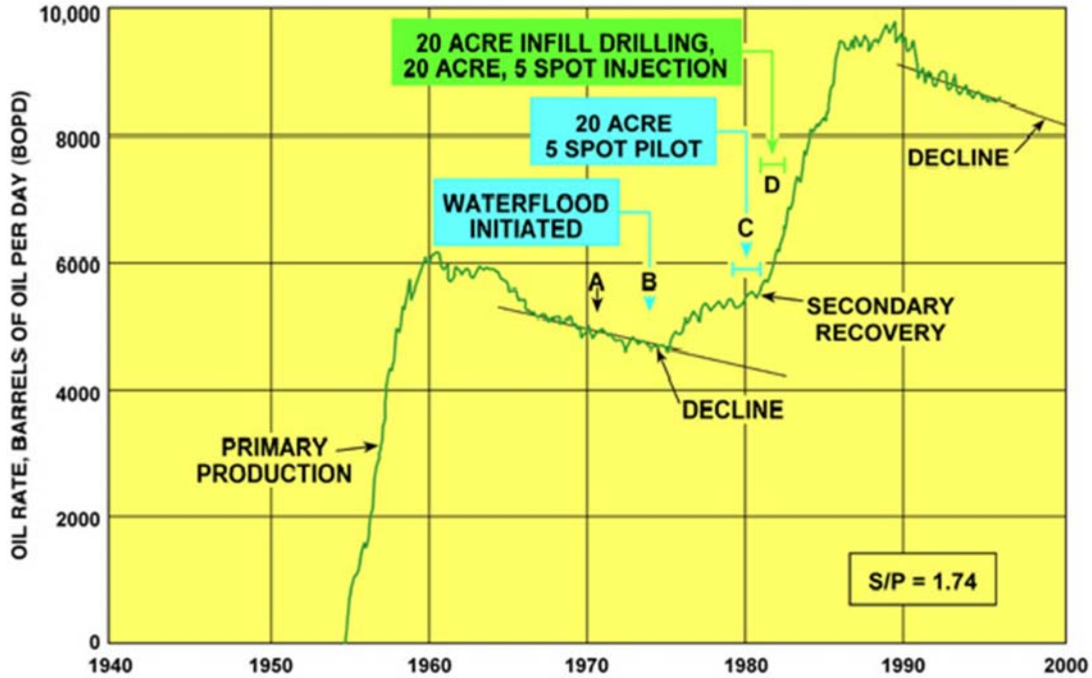
- **The natural drainage of oil reservoirs often leads to low recovery factors**
  - Additional energy has to be injected into oil reservoirs in order to achieve higher recovery
  - First solution is to **inject fluid**, water and/or gas, in the reservoir => **Secondary recovery**

- **Objectives: to increase the reserves**
  - By **supporting the pressure**
  - By **improving the sweeping efficiency** of the hydrocarbon zone

- **Methods**
  - Water injection (in the aquifer or in the lower part of the oil zone) => **water flooding**
  - Gas injection (in the gas cap or in the top on the oil zone) => **gas flooding**

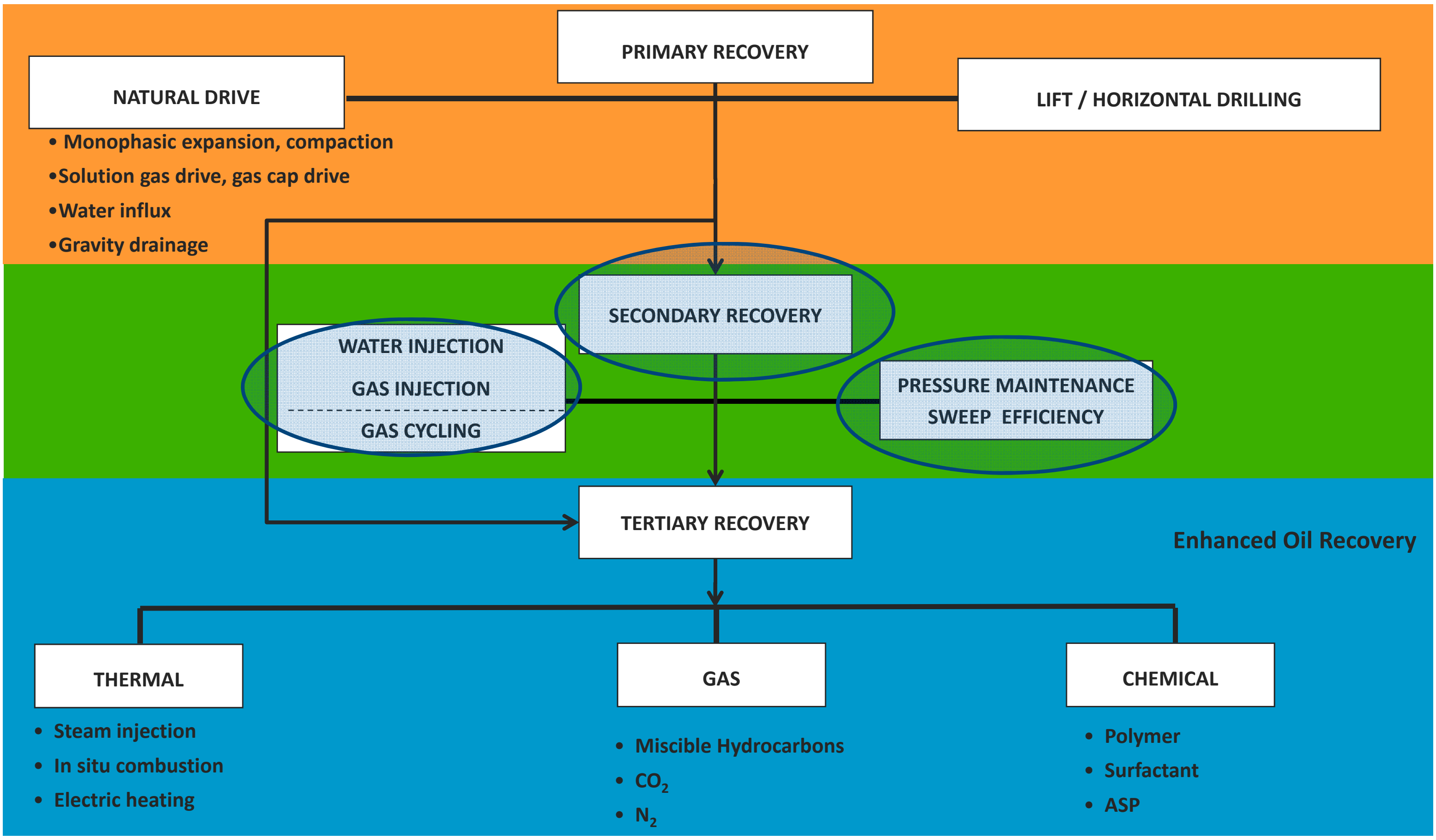
Introduction to secondary recovery

Example of secondary recovery



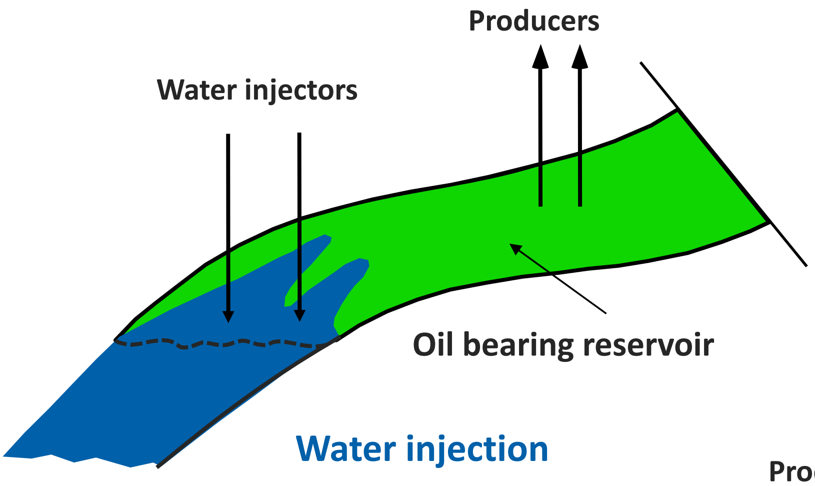
From Sneider

Introduction to drive mechanisms

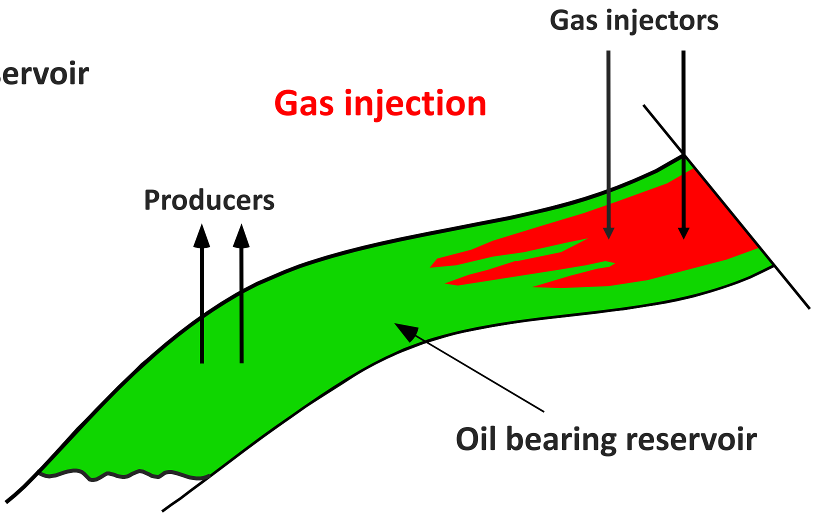


Introduction to secondary recovery

Water injection / Gas injection



- Water injection: simultaneous flow of water and oil within the reservoir



- Gas injection: simultaneous flow of gas and water within the reservoir

Introduction to secondary recovery

Evaluation of drive mechanisms

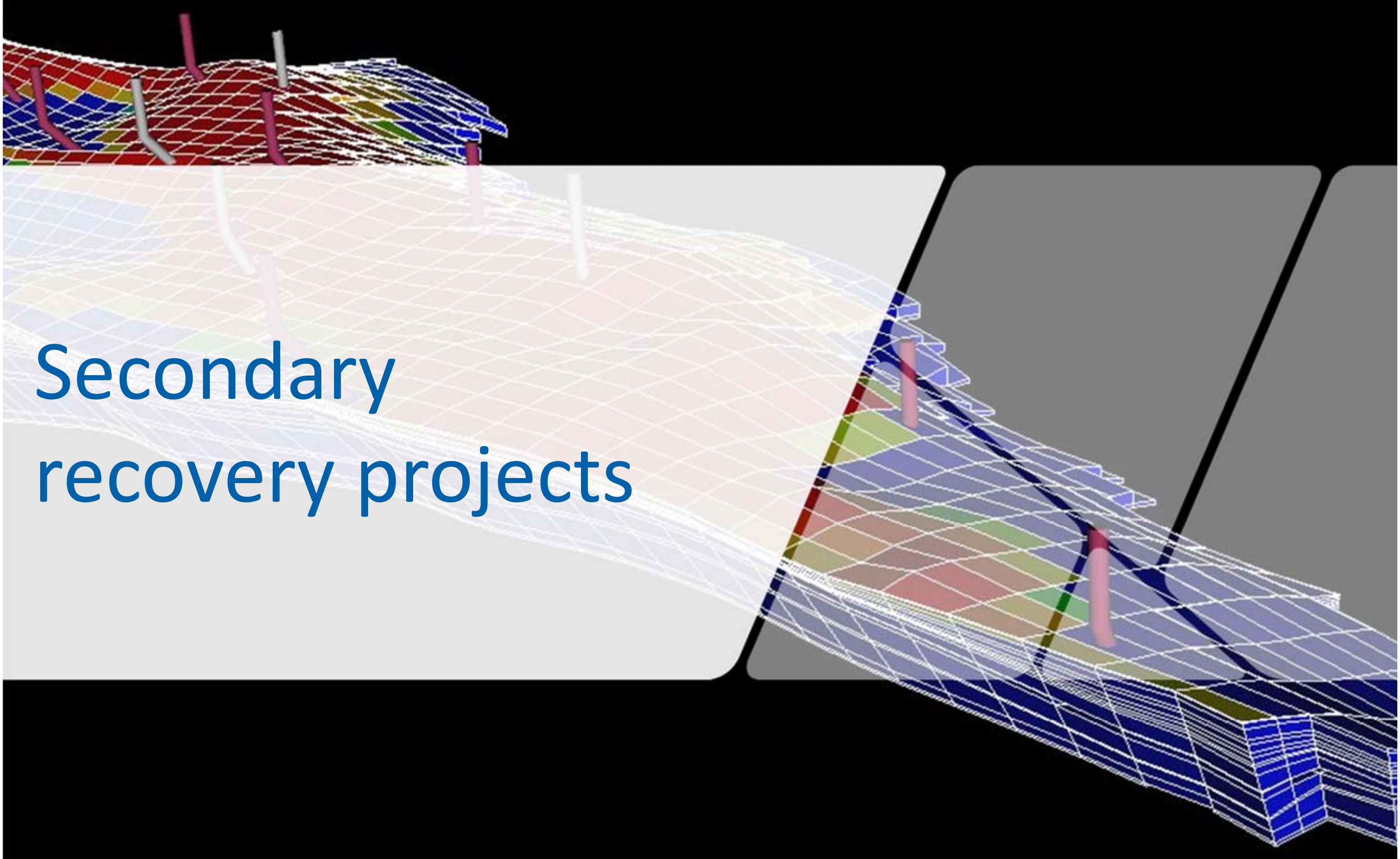
- **Reservoir engineers have to determine from the onset the reservoir production mechanisms: natural or assisted drainage (water/gas/steam injection,…)**
- **Generally, assisted drainage is preferred because of higher recovery factors but natural drainage mechanisms always have to be determined in order to optimize assisted drainage**
- **It is interesting to start producing the reservoir through natural depletion, even for a very short period, in order to observe its behavior and determine the type of natural drainage mechanisms underway from the analysis of production data**
- **However, assisted drainage is more and more often implemented right from the beginning in order to achieve a higher recovery,**
  - Especially since early recovery is highly valuable
- **As engineers learn more about the reservoir, the initial FDP may be changed**
  - Adding new wells, either producers or injectors, converting producers to injectors, etc,
- **Nevertheless, uncertainties may remain, in particular aquifer activity**

Parameters to define /optimize

- **Many parameters have to be defined / optimized:**
  - Nature of the fluid to be injected (water, gas, steam, …)
  - Injection zone (top, bottom, aquifer, all…)
  - Injection pattern (grouped flood, dispersed flood,...)
  - Optimum level of pressure support
    - injection rate, continuous/alternate injection,…
    - number of injection wells
    - planning
  - Field surveillance and data acquisition to monitor the results of injection strategy implementation vs. forecast
  - Data input for well architecture/completion design and for surface facilities design

- **The main objective of secondary recovery is to increase hydrocarbon reserves by:**
  - **Supporting pressure** in the reservoir
  - **Improving the sweep efficiency** of the reservoir
- **The most commonly used solution is to inject fluid:**
  - Water injection, in the aquifer or in the oil zone near the WOC
  - Gas injection, in the gas cap or in the oil zone near the GOC
- **Secondary recovery implies multiphase flow in the reservoir**
  - Water/oil displacement in case of water injection
  - Gas/oil displacement in case of gas injection
- **To be optimized, assisted drainage requires information on natural drainage, but it is often implemented without sufficient appropriate information**
  - FDP will be updated all along the reservoir life to optimize the secondary recovery by taking information coming from dynamic/production data analysis into account

Secondary recovery projects



Secondary recovery projects

Oil reservoirs drive mechanisms and injecting fluids

- **Which kind of drive mechanisms are favorable for secondary recovery?**
  - Undersaturated depletion
    - Waterflooding: it may prevent pressure to drop below bubble point and avoid free gas flowing in the reservoir; it will also improve Rf otherwise very low
    - In some cases, allowing pressure to drop below the bubble point can be favorable because of triphasic effects (solution gas mobilizing the oil and slowing down the water)
  - Solution gas drive reservoirs
    - Very good candidates for waterflooding since these reservoirs may exhibit rapid pressure and production decline and still quite low recovery factors
    - May also be good candidates for gas injection because of the large quantity of associated gas available at the beginning of the process
  - Gas cap reservoirs
    - Good candidates for waterflooding but attention has to be paid to avoid losing water in the gas cap or pushing the oil into the gas cap
    - May be also very good candidates for gas injection since associated gas is available and it is possible to inject directly in the gas cap with very good injectivity
  - Natural water drive reservoirs
    - Waterflooding may be applicable in the case of weak water drive in order to improve pressure support and recovery

Nature of injected fluids

- **Performance of injection**
  - One of the main driving parameters of the fluid injection performance is **the mobility ratio M** that has to be as low as possible in order to avoid instabilities hence a quite viscous injection fluid
  - As a consequence water is well adapted for light oils, but less for heavy oils
  - In any case, injected **gas poorly sweeps oil in place** due its lower viscosity but immiscible gas injection can be turned into **miscible** gas injection and achieve better performance
  - Generally water injection is performed first, then gas injection, before moving possibly to EOR in order to further increase the performance (miscible gas, WAG and finally possibly chemical e.g. SP, ASP, FAWAG depending on the case etc.)
- **Treatment**
  - Water treatment is generally easier than gas treatment
- **Availability**
  - **Key factor** for implementing a secondary recovery injection scheme
  - Water availability is generally higher than gas availability (mainly non-marketed associated gas) but gas injection can be seen as a way to increase value after the prohibition of venting or flaring

Injection pressure

- **One of the main objectives of water injection is to maintain (or support) the reservoir pressure, especially above bubble point pressure in order to avoid free gas in the reservoir**
  - To prevent the increase in oil viscosity by « losing » the lighter components
  - To prevent the decrease in oil relative permeability because of the increase in gas saturation
  - To maintain good wells productivity (IPR)
  - To prevent a sharp increase in GOR and related problems at the surface
- **As a rule of thumbs, the typical target for pressure maintenance should be a few bars to a few tens of bars above bubble point pressure**
  - High pressure maintenance requires high pressure head and may be costly
  - However, it is much easier to inject water than gas because of the higher value of B_w compared to B_g that decreases roughly as $1/P$ => as a consequence, the volumes of water to deal with at the surface are much lower and the corresponding equipment is less costly
- **The target in pressure may typically rule the start of the injection period**

Volume of fluid injected

- **For the reservoir pressure to be strictly maintained, there should be a strict balance between the injected fluid volume and the fluid voidage at reservoir conditions**
- **If no other mechanism is involved (e.g. active aquifer), the injected fluid volume should compensate the produced volumes at reservoir conditions:**

injection rate = production rate @ res. conditions

$$Q_{winj}B_{winj} + Q_{ginj}B_{ginj} = Q_oB_o + Q_{wp}B_{wp} + Q_{fg}B_{fg}$$

where Q_{fg} is the surface flowrate of free gas $Q_{fg} = Q_o(GOR - R_s)$

- **Actually, the injected volume will also depend on the availability of the fluid for injection**

Secondary recovery projects

Voidage replacement ratio

- **It is the ratio of the injected volumes to produced volumes in reservoir conditions**
  - Instantaneous *VRR*

$$VRR = \frac{Q_{winj}B_{winj} + Q_{ginj}B_{ginj}}{Q_oB_o + Q_o(GOR - R_s)B_g + Q_wB_w}$$

  - Cumulative *VRR*

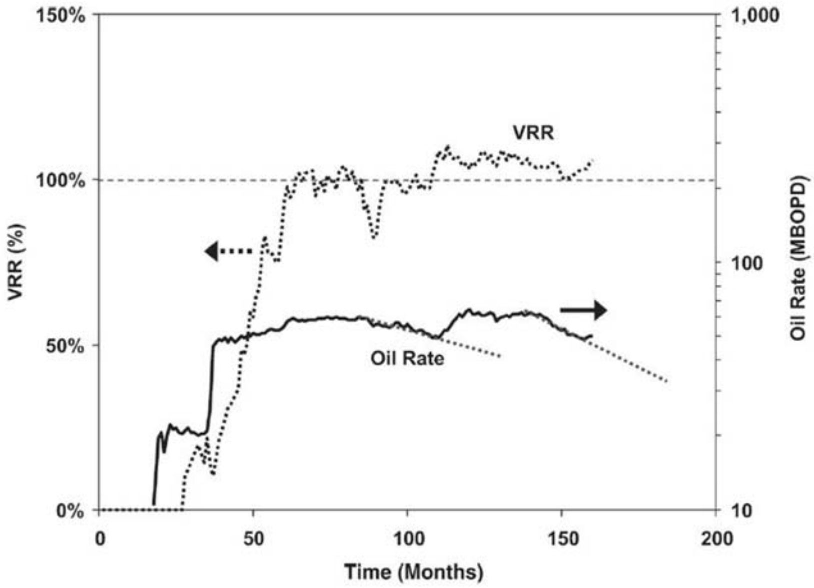
$$VRR = \frac{W_{inj}B_{winj} + G_{inj}B_{ginj}}{N_pB_o + N_p(R_p - R_s)B_g + W_pB_w}$$

  - *VRR* target should be 1 or above 1 in order to maintain pressure
    - In some cases it can be interesting to let the VRR fall well below 1 in order to let the pressure drop below bubble point and benefit from the **triphasic effects**
  - Cumulative *VRR* are typically calculated on a monthly or three-month basis and since the beginning of the injection process
    - Monthly cumulative *VRR* may help to identify injection losses or unexpected fluids influx into the reservoir
    - As long as the overall cumulative *VRR* is equal to or above 1, it can be said that the reservoir pressure has been maintained from the beginning of the injection process

Secondary recovery projects

Voidage replacement ratio and oil flowrate

- **Plotting *VRR* together with the oil rate may help understand the relationship between the two**
  - The below figure displays VRR and the oil flowrate (log scale) vs. time for El Trapial field (Argentina) and shows a clear relationship between the two



After Terrado & al.
SPE102200

Secondary recovery projects

Injection pattern

- **The injection pattern, i.e. the relative layout of injection and production wells is critical for the success of a waterflooding / gas flooding project**

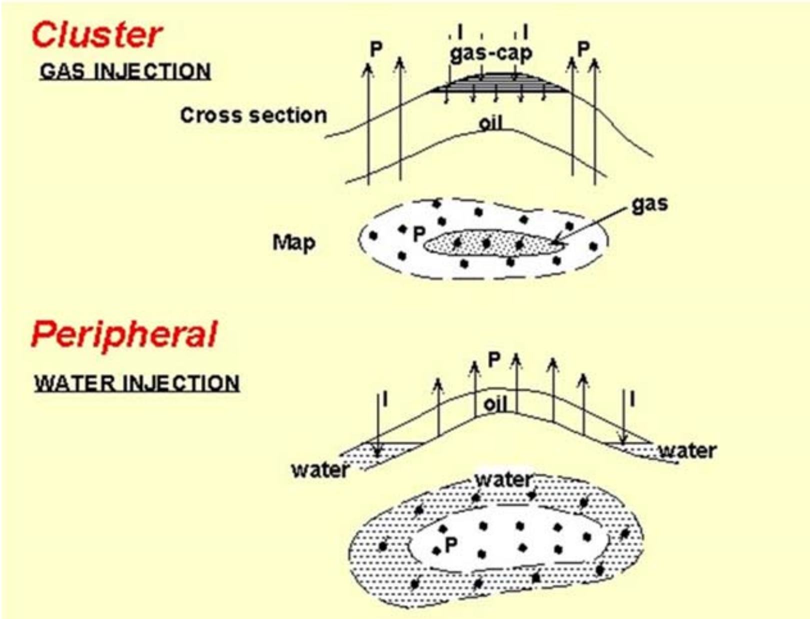
- **It strongly depends on the reservoir geometry, the reservoir heterogeneity especially in permeability, the fluid content and the volume to be swept**

- **There are two kinds of injection patterns**
  - **Grouped flood** where injection wells are grouped locally
  - **Dispersed flood** where injection and production wells are alternatively located

Secondary recovery projects

Grouped injection pattern

- **In the case of high-dip reservoir (gravity effects) or high permeability reservoir (with associated low pressure gradient), injection wells are located to get a regular displacement i.e. piston-like allowing to sweep large areas with late breakthrough at the production wells => grouped flood**
  - In case of gas, injection is made close to the GOC or in the gas-cap if any, or at the top of the structure => **central flood**
  - In case of water, injection is made in the aquifer or near the WOC => **peripheral flood**



Secondary recovery projects

Dispersed injection pattern

- **If the reservoir shows no gravity effect (horizontal) or exhibits low permeability, only a very limited zone is effectively flooded**

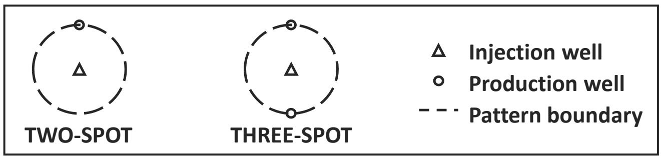
  => production and injection wells are laid out in a fairly regular pattern in the oil zone termed dispersed flood

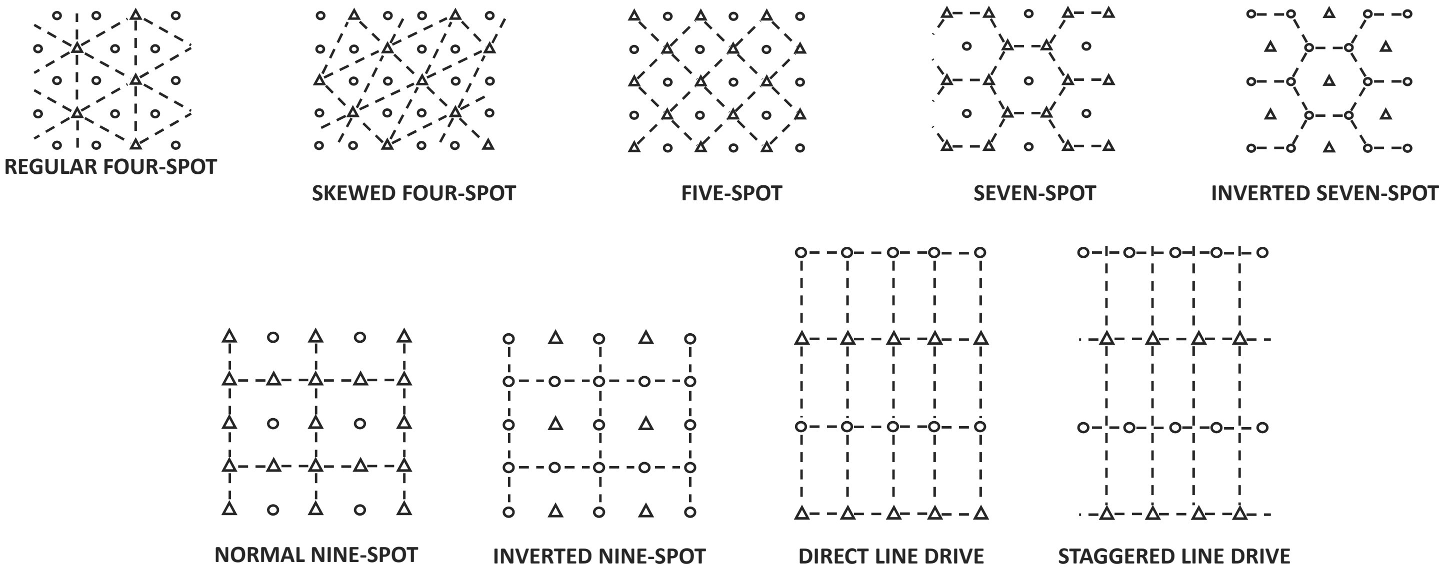
- **Several patterns are considered as characterized by their geometry and the ratio injectors/producers:**
  - I / P ratio
    - 5 – spot   I = P
    - 7 – spot   I / P = 2 regular
    - I / P = 1 / 2 inverse
    - 9 – spot   I / P = 1 / 3

Secondary recovery projects

Dispersed injection pattern - Wells patterns

Pattern

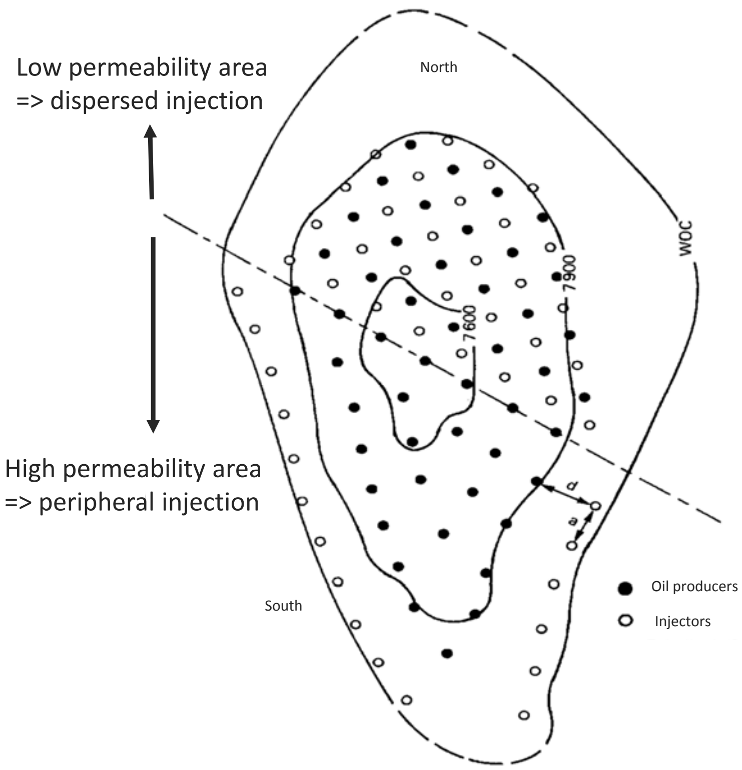




Secondary recovery projects

Wells locations

- **The production/injection scheme is designed according to the reservoir characteristics**
  - Distance between wells
  - Relative location of injectors and producers
- **Due to high complexity (heterogeneities, faults, etc.), reservoir simulation is generally needed to determine actual optimal well locations**
- **With time:**
  - Producers may be turned into injectors
  - Additional injectors may be drilled: **infill drilling**



Waterflooding - Some history

- **Waterflooding is the most widely used secondary recovery technique**

- **Water injection began in the U.S. as early as the end of 19th century and it developed widely early in the 20th century**
  - The first concern was about production water management: as the fields became mature, more and more water was produced and disposal in rivers became more and more difficult => start of water injection included within the reservoir interval
  - Injection of water was generalized by the 1920-1930s
  - In parallel, engineers recognized the very low recovery factors obtained from primary recovery and the improvement of recovery due to water injection
  - By the 1940s, secondary recovery with water injection began to be systematically implemented in the U.S. and engineers began to work on modeling and optimizing water injection

Waterflooding – Injectivity

- **Well injectivity is one of the major concern and source of uncertainty within a secondary recovery project**
- **Well injectivity depends on the location:**
  - In the water zone, Injectivity Index *II* is given by:

$$II = \frac{Q_w}{P_{winj} - P_r} = 0.00708 * \frac{kh}{\mu_w B_w \left[ln\frac{r_e}{r_w} + S\right]}$$

  - In the oil pool, Injectivity Index *II* is given by:

$$II = \frac{Q_w}{P_{winj} - P_r} = 0.00708 * \frac{kk_{rw}h}{\mu_w B_w \left[ln\frac{r_e}{r_w} + S\right]}$$

=> The injectivity index is better in the water zone since $k_{rw} \approx 0.3$ but if injecting in the water zone, the effectiveness will strongly depend on the quality of communication between the aquifer and the oil pool (especially vertical permeability) and the quality of the permeability distribution in the water zone (largely unknown)

Waterflooding - Practical considerations

Water sources

- Fresh surface water
- Offshore: sea water
- Water from a different reservoir (above, below, ….)
- Produced water

Potential problems

- Compatibility with formation water ($BaSO_4$, $CaCO_3$ precipitates)
- Water filtration
- Biocides to prevent H_2S generation
- Oxygen removal

Injection of tracers for monitoring the waterflooding

Waterflooding – Performance and related parameters

Volumetric recovery

- Recovery at the reservoir scale, by respect of the part of the volume that is contacted
- Derived from the flow simulation (cross section & full field model)
- Can be high in the case of a favorable mobility ratio M

Microscopic recovery

- Recovery at the scale of the pore, i.e. the part of the pore volume that is filled with water within the pores which are contacted by the waterflood
- Derived from the relative permeability curves
- Generally quite low because of high value of residual oil saturation

Overall performance

- Can be as high as 50-60%
- Driving parameters
  - Permeability distribution
  - Relative permeability & water/oil mobility ratio
  - Faults - Compartmentalizing
  - Replacement rate
  - …

Waterflooding – Gravity drainage

- **Other mechanisms may have an impact on recovery, depending on the context (geology, fluid):**
  - Capillarity
  - Gravity drainage
  - ...

- **Gravity drainage can dramatically enhance the sweep efficiency by stabilizing the flow**
- **Gravity drainage is favored by the following situations:**
  - High reservoir dippage
  - Strong vertical permeability $\boldsymbol{k_v}$ and no vertical permeability barriers
  - High water-oil density contrast
    - Better with light oil

Gas injection – Performance

- **Main drawback**
  - Due to low viscosity ($\boldsymbol{\mu_g = 0.01\ cP}$), the mobility ratio $\boldsymbol{M}$ is high, instabilities develop and the volumetric sweep efficiency is low => only a small part of the area under injection is effectively flooded
    - Highly sensitive to permeability heterogeneities
- **The overall performance is generally lower than water injection but**
  - A high $\Delta\boldsymbol{\rho_{og}}$ leads to good segregation especially in case of reservoir dippage and, if $\boldsymbol{k_v}$ is high, gas injection results in a very efficient gravity drainage with a recovery as high as 60-70%
  - A higher gas mobility gives capacity to flood a part of the reservoir that has not yet been swept by the water
  - The residual oil saturation to gas S_{org} can reach very low value, in the range of 5%, thus leading to high microscopic efficiency
    - Additionally immiscible gas injection can be turned to miscible gas injection achieving very high microscopic efficiency
  - Gas injection may come in support of waterflooding in order to further increase the recovery by remobilizing isolated oil and flooding areas kept unswept

Secondary recovery projects

Gas injection – Practical aspects

- **Injectivity**
  - Taking into account low μ_g, injection wells have high injectivity => less gas injectors (typically less than for producers)
  - But necessity of high wellhead injection pressure => compressors
- **Availability**
  - One of the main concerns: finding gas
  - Large volumes of gas needed
  - Most of the time, the injection gas comes from produced gas (**associated gas**)
  - Associated gas was usually flared but flaring has become more and more difficult because of environmental concerns => reinjection can be a valuable solution but the increasing concern for "marketing" associated gas may become a problem for secondary recovery project
  - Injection may also be a solution to valorize gas in the case of gas condensates reservoir

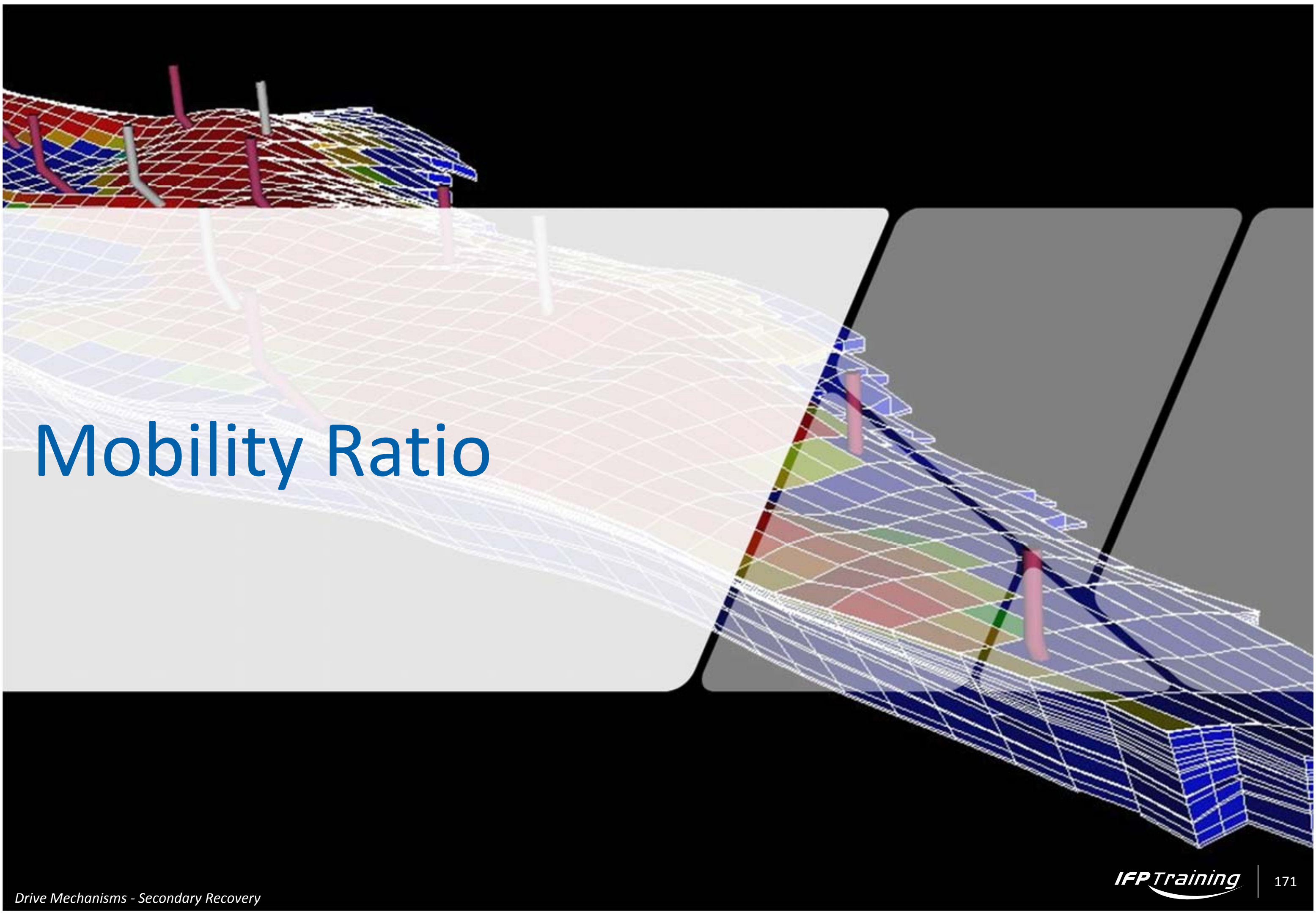
Secondary recovery projects

- **Waterflooding is the most widely used secondary recovery method since**
  - The availability is generally better
  - The treatment is generally easier
  - The sweeping efficiency is generally better
  - The overall performance can be as high as 50-60%
- **Gas injection may be used to further improve recovery**
  - The sweeping efficiency is generally lower but microscopic efficiency is better because of lower residual oil saturation to gas
  - A higher mobility allows to flood areas unswept by water and may help to remobilize isolated oil
  - The overall performance can be as high as 60-70% in case of a favorable gravity drainage, otherwise generally lower than for waterflooding
  - Immiscible gas injection can be turned to miscible gas injection with even better performance (cf. EOR)
  - Main concern: gas availability and related cost

Secondary recovery projects

- **The injection pattern is of two types:**
  - Grouped flood in the case of high-dip reservoir or high permeability reservoir: central flood in case of gas injection, peripheral flood in case of water injection
  - Dispersed flood in the other case using patterns like 5-spot, 7-spot etc.
  - In general, a reservoir simulation is used to optimize well locations
- **Well injectivity**
  - Critical but very often difficult to forecast
- **Pressure**
  - Typically a few bars to tens of bars above bubble point pressure
- **Overall performance strongly depending on the reservoir geology**
  - Deep knowledge of the reservoir mandatory, especially heterogeneity
  - Monitoring of the performance over time (cf. *VRR*)
- **Surface facilities, especially treatment facilities, have to be designed accordingly**

Note



Mobility Ratio

Mobility Ratio

Definition

- **Definition:**

$$M = \frac{\textit{mobility of the displacing phase}}{\textit{mobility of the displaced phase}}$$

With

$$\textit{fluid mobility} = \frac{\textit{fluid effective permeability}}{\textit{fluid viscosity}}$$

- **Case of water injection (water flooding)**

$$M_{w/o} = \frac{\textit{mobility of water}}{\textit{mobility of oil}} = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o} = \frac{k_{rw}}{k_{ro}}\frac{\mu_o}{\mu_w}$$

- **Case of gas injection (gas flooding)**

$$M_{g/o} = \frac{\textit{mobility of gas}}{\textit{mobility of oil}} = \frac{k_{rg}/\mu_g}{k_{ro}/\mu_o} = \frac{k_{rg}}{k_{ro}}\frac{\mu_o}{\mu_g}$$

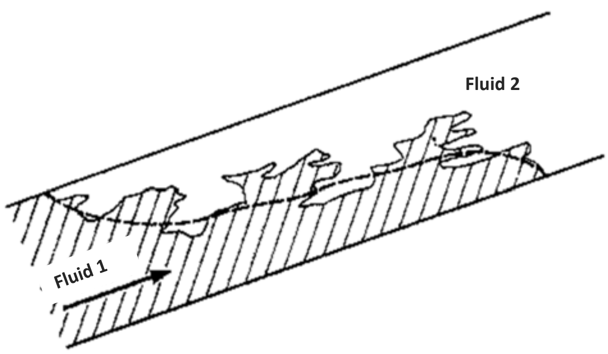
Mobility ratio and flow stability

- **Instabilities in multiphase flows**
  - When the reservoir is thick and vertical velocities cannot be ignored, it can be shown through the analysis of forces that **distortions** or **encroachments** may appear and develop at the fluid interfaces
  - These encroachments occur at different scales:
    - fingering at small scale
    - tongues at the scale of the reservoir
    - coning near the well
  - Encroachments are governed by conditions of stability or instability of the flow
  - Among the parameters governing instabilities is the mobility ratio $\boldsymbol{M}$: **the lower the mobility ratio, the better the stability of the displacement**
    - The lower the mobility contrast between the displacing fluid and the displaced fluid, the more stable and the more efficient the displacement

Favorable and unfavorable mobility ratio

- **It can be shown in laboratory that fingering starts to develop at microscopic scale when $\boldsymbol{M > 1}$ and tends to disappear when $\boldsymbol{M < 1}$**

- **A mobility ratio $\boldsymbol{M}$ above 1 is said to be unfavorable while a mobility ratio below 1 is said to be favorable**



Mobility ratio

Calculation of mobility ratio

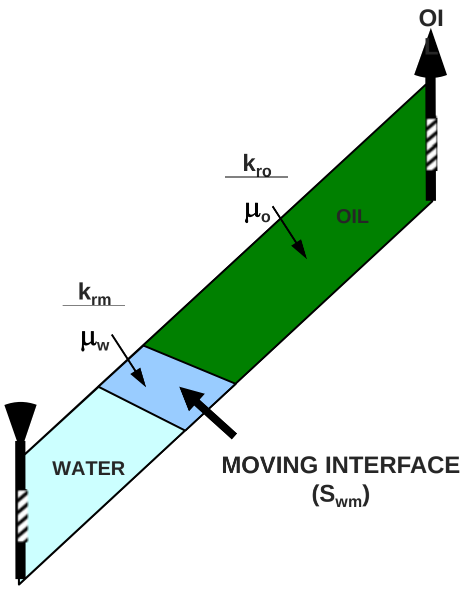
Definition

- In the case of oil/water displacement:

$$M = \frac{k_{rw}(S_{wm})}{\mu_w} \frac{\mu_o}{k_{ro}(S_{wi})}$$

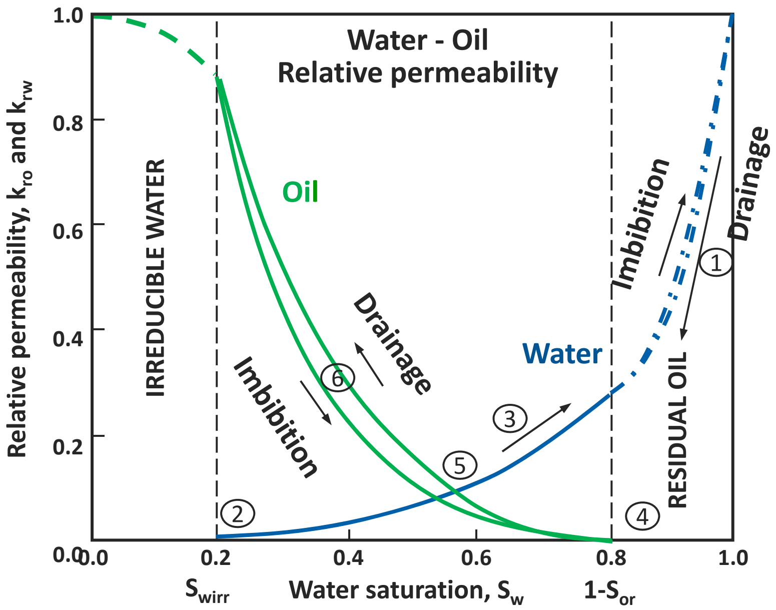
where S_{wm} is the average water saturation behind the front and $k_{rw}(S_{wm})$ is the corresponding water relative permeability (from k_r curve)

- If the viscosity contrast between the two fluids is not too high, then $\mathbf{S_{wm}}$ is close to $\mathbf{S_{wmax} = 1 - S_{orw}}$ (i.e. the endpoint of the $\mathbf{k_r}$ curve) => **end-points mobility ratio**
- Otherwise, we should need to use $\mathbf{S_{wm}}$ estimated from Welge tangent analysis (see below)
  - Actually, the end-point mobility ratio is generally used to decide on the stability condition



Relative permeabilities

K_r curves - Example of oil/water system



1: S_w decreases => drainage (corresponding to the initial flooding of oil in the reservoir supposed initially water-wet)

2: S_{wirr} irreducible water saturation : only oil moves k_{ro}=0.8 & k_{rw}=0

3: S_w increases => imbibition (corresponding to oil production)

4: S_{or} residual oil saturation : only water moves, oil is immobile

5: crossing point : $k_{ro}=k_{rw}$ and $k_{ro}+k_{rw} < 1$

6: hysteresis : not the same curve for imbibition and drainage due to difference in invasion process between wetting fluid and non-wetting fluid (effect of capillary pressure); hysteresis is generally more marked for the non-wetting fluid

- Except for the end points, the sum of the relative permeabilities is always < 1 => each fluid disturbs the flow of the other one
- K_r curves dictate the fluids flow in the reservoir and are used for reservoir simulation

Mobility ratio

Examples of typical values of M

Displaced fluid	Displacing fluid	k_{ro}	k_{rw}	k_{rg}	μ_o (cP)	μ_w (cP)	μ_g (cP)	M
Light oil	Water	0.9	0.3		0.5			0.28
Medium oil	Water	0.9	0.3		5			2.8
Light oil	Gas	0.9		0.5	0.5		0.02	13.9
Medium oil	Gas	0.9		0.5	5		0.02	139
Gas	Water		0.3	0.9		0.6	0.02	0.01

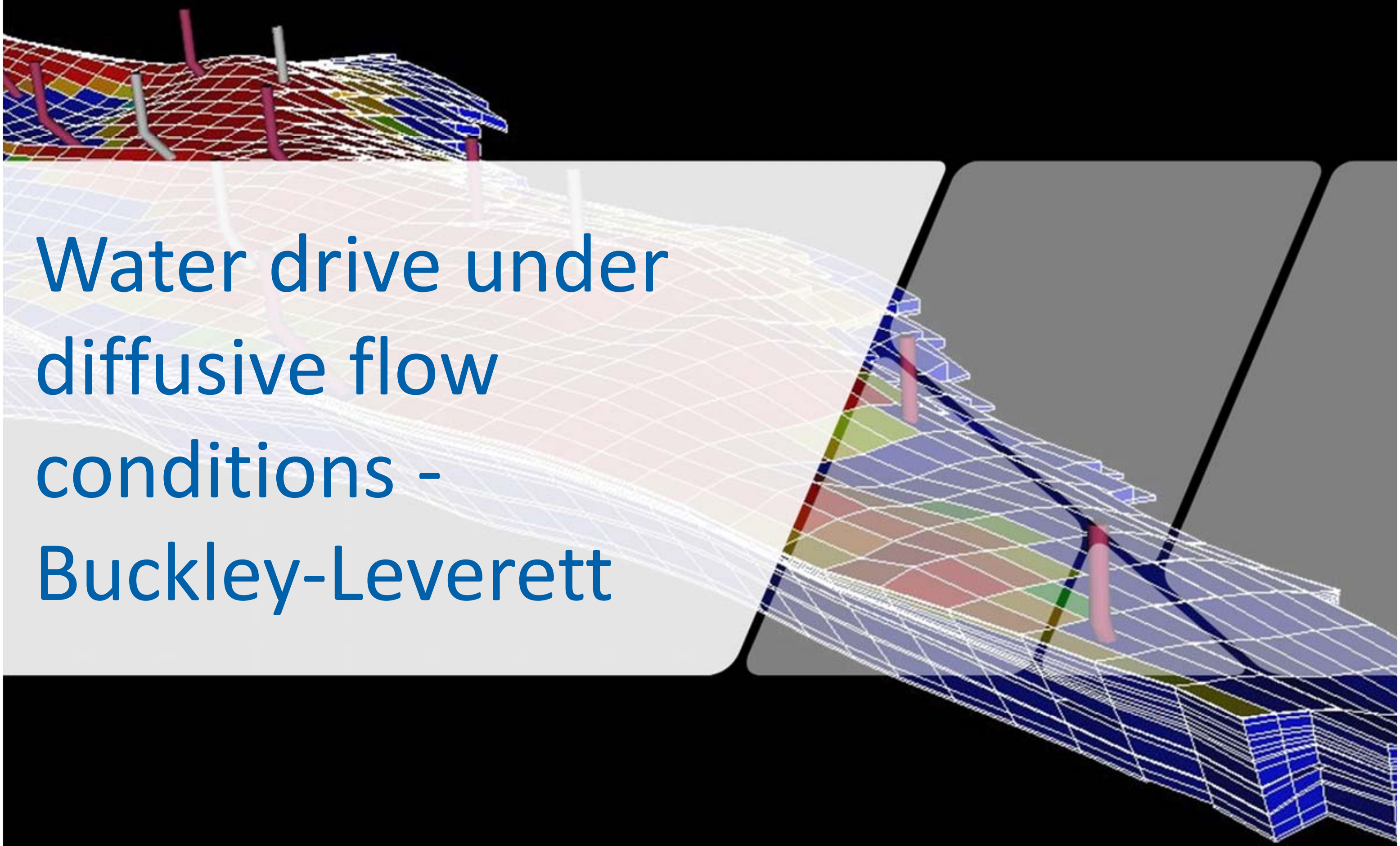
From Cossé

Mobility Ratio

- **Mobility ratio M is defined as the ratio of the mobility of the displacing phase to the mobility of the displaced phase**

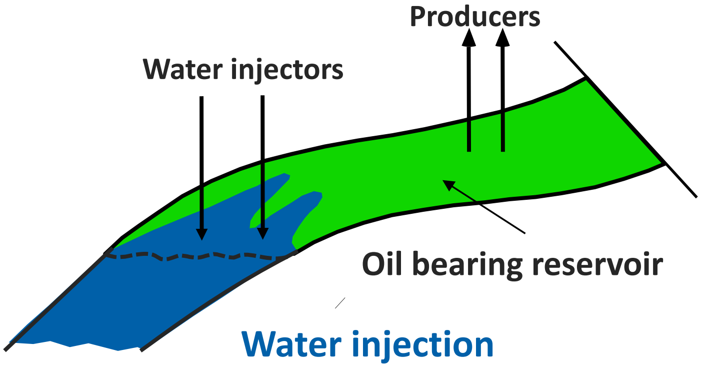
- **M is one of the main parameters governing the instabilities which may develop during multiphase flow and affect the sweep efficiency (tongue, fingering)**

- **If $M < 1$ it is favorable ; if $M > 1$ it is unfavorable**
  - M is favorable only in some cases for light oil displaced by water; displacement of oil by gas always leads to an unfavorable gas ratio due to very low gas viscosity
  - An unfavorable M leads to a low value of S_{wm} far from maximum water saturation => more oil trapped behind the displacement front

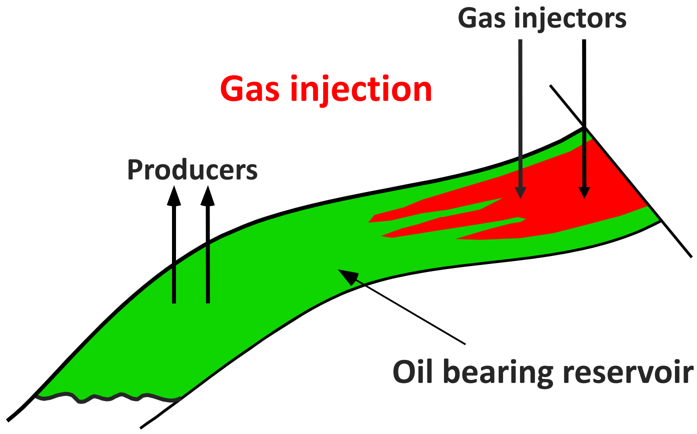


Water drive under diffusive flow conditions - Buckley-Leverett

Water injection / Gas Injection



- **Water injection**
  - into or close to the WOC
  - The WOC is rising into the reservoir => **one mobile interface water/oil**



- **Gas injection**
  - Into or close to the gas cap if any, at the top of the structure otherwise in order to form a secondary gas cap
  - The gas cap is getting down into the reservoir => **one mobile interface gas-oil**

Main assumptions of diffusive flow

- **Immiscible fluids**
  - Typically water displaces oil in a water-wet reservoir
- **Displacement occurs under condition of vertical equilibrium**
  - Saturations are distributed under capillary-gravity equilibrium according to the equation:

$$P_c(S_w) = \Delta\rho . g . \cos\theta . h$$

  - The vertical velocities are considered as infinite compared to the horizontal velocity

=> S_w is **instantaneously** redistributed by respect to the previous equation

=> **fluid saturations are uniformly distributed with respect to thickness**

=> unidirectional displacement of **a water saturation front**

- **Displacement is considered to be incompressible**
  - Total fluid replacement => reservoir pressure is maintained

$$q_t = q_o + q_w = q_{inj}$$

- **Displacement is linear**

Diffusive flow – Buckley-Leverett theory

Conditions for vertical equilibrium

- **Vertical equilibrium is enhanced by**
  - A high value of permeability, especially vertical permeability
  - A high value of density contrast between fluids
  - Low fluid viscosities
  - A low reservoir thickness
  - High value of capillary forces, i.e. large transition zone

- **Diffusive flow applies typically**
  - In plug/core flows, in laboratory
  - Within the reservoir with large transition zone where there are major capillary forces

- **But was found valid with good results within most of the reservoirs**

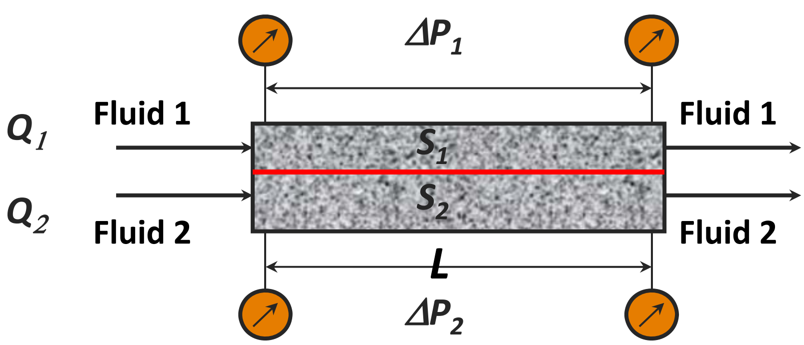
Diffusive flow – Buckley-Leverett theory

Remainder on relative permeabilities

- **The classic Darcy's law is valid for monophasic flow only and it needs to be extended to take the reservoir multiphasic flows into account**
- **Case of diphasic flow**
  - Two fluids flowing in the porous medium
  - The monophasic Darcy's law is extended by introducing the **effective permeability** that takes the presence of the other fluid in the porous medium into account

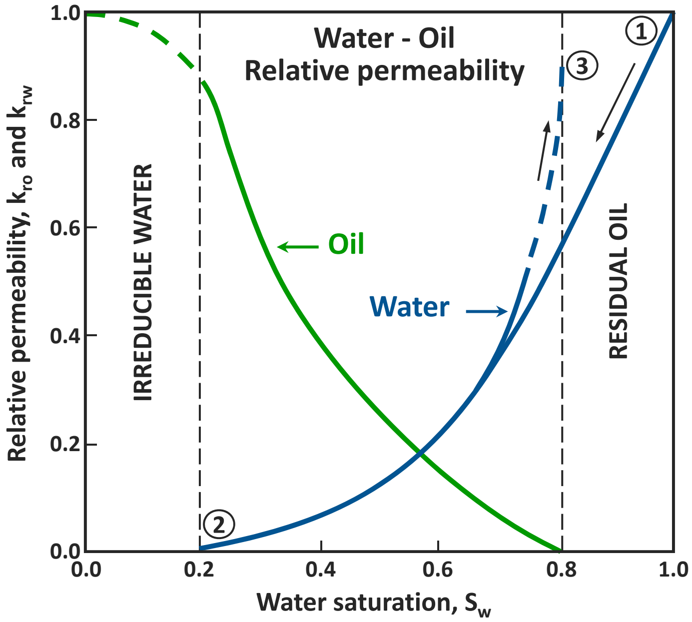
$Q_1 = \frac{k_1}{\mu} A \frac{dP_1}{dx}$ where k_1 is the effective permeability of fluid 1 by respect to fluid 2

$Q_2 = \frac{k_2}{\mu} A \frac{dP_{2w}}{dx}$ where k_2 is the effective permeability of fluid 2 by respect to fluid 1



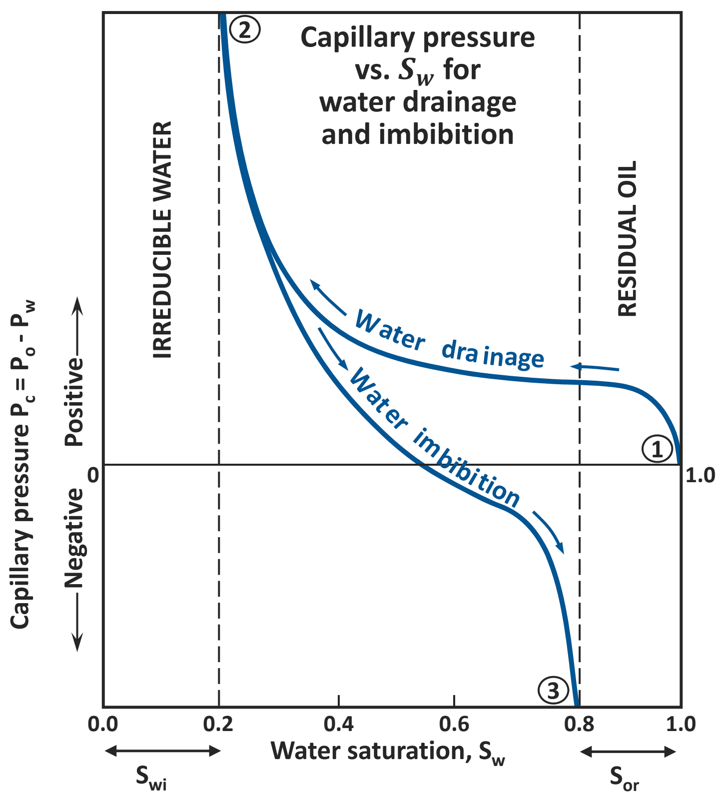
Diffusive flow – Buckley-Leverett theory

Kr-Pc reminders



$$q_o = \frac{kk_{ro}}{\mu} A \frac{dP_o}{dx} \text{ with } k_{ro} = k_o/k$$

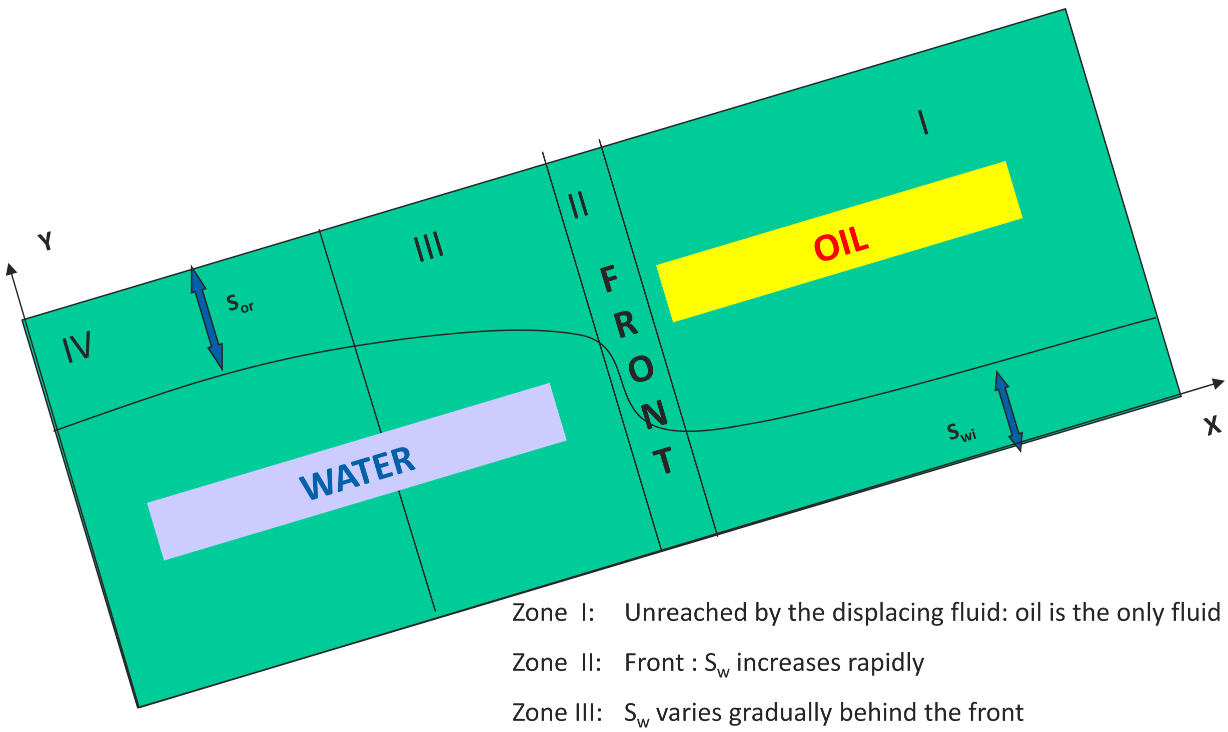
$$q_w = \frac{kk_{rw}}{\mu} A \frac{dP_w}{dx} \text{ with } k_{rw} = k_w/k$$



Diffusive Flow – Buckley-Leverett theory

Frontal Displacement

- Case of two immiscible fluids (oil and water); unidirectional flow



Zone I: Unreached by the displacing fluid: oil is the only fluid in movement

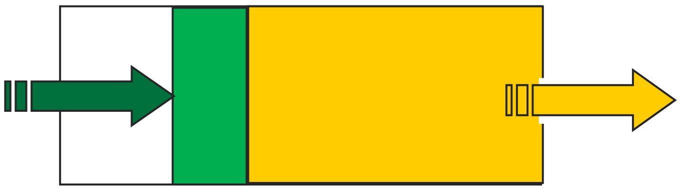
Zone II: Front : S_w increases rapidly

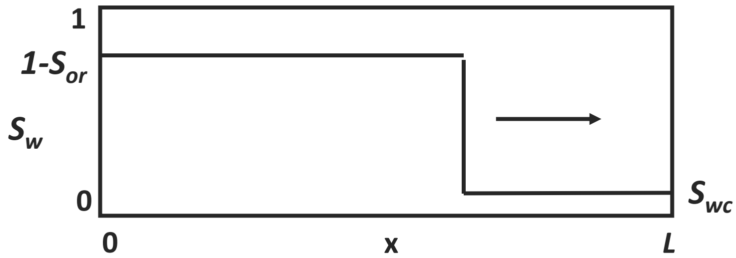
Zone III: S_w varies gradually behind the front

Zone IV: Flooded by water: water is the only fluid in movement; residual oil S_{or}

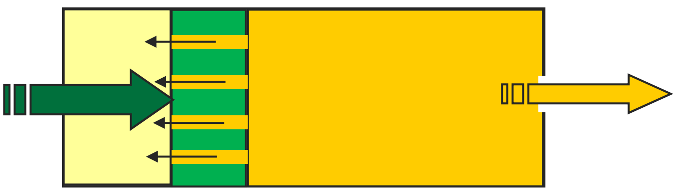
Ideal and real displacement

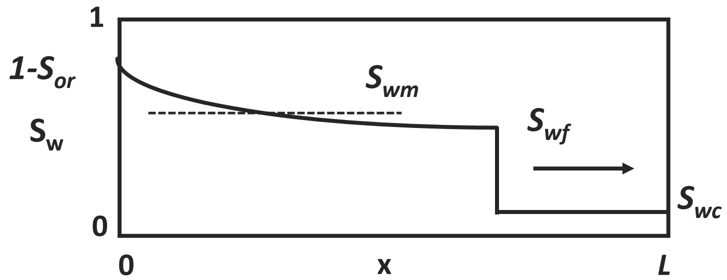
Ideal displacement: piston-like displacement





Real displacement: function of k_r, μ, k, ρ, q, dip → Leaky Piston type displacement



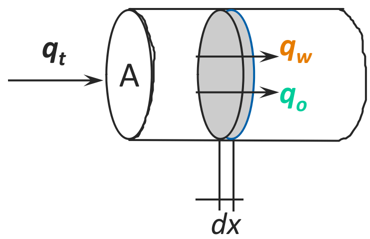


Diffusive flow – Buckley-Leverett theory

Unidirectional frontal displacement

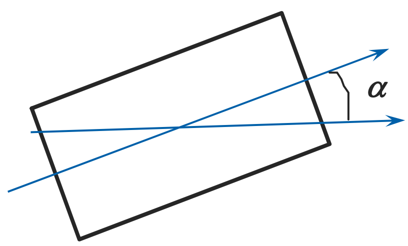
- One can demonstrate that within a section of width dx, the ratio q_w/q_t depends on the water saturation S_w only
- Darcy's law writes (without gravity):

$$q_o = -\frac{k_o A}{\mu_o} \cdot \frac{dP_o}{dx}$$
$$q_w = -\frac{k_w A}{\mu_w} \cdot \frac{dP_w}{dx}$$



- Gravity introduces an additional term along with the pressure gradient in Darcy's law

$$q_o = -\frac{k_o A}{\mu_o} \cdot \left(\frac{dP_o}{dx} + \rho_o g sin\alpha\right)$$
$$q_w = -\frac{k_w A}{\mu_w} \cdot \left(\frac{dP_w}{dx} + \rho_w g sin\alpha\right)$$



Fractional flow equation

- **Introducing capillary pressure $P_c = P_o - P_w$ we get:**

$$-\frac{q_o\mu_o}{k_oA} = \frac{dP_o}{dx} + \rho_o g sin\alpha \quad (1)$$

and

$$-\frac{q_w\mu_w}{k_wA} = \frac{d(P_o - P_c)}{dx} + \rho_w g sin\alpha \quad (2)$$

- **Subtracting (1) from (2) we get:**

$$-\frac{q_w\mu_w}{k_wA} + \frac{q_o\mu_o}{k_oA} = \frac{-dP_c}{dx} + \Delta\rho g sin\alpha$$

$$-\frac{\mu_w k_o}{\mu_o k_w} q_w + q_o = \frac{-k_oA}{\mu_o}\left[\frac{dP_c}{dx} - \Delta\rho g sin\alpha\right] \quad (3)$$

- **Introducing fractional flow (or water-cut) f_w in equation (3)**

$$f_w = \frac{q_w}{q_w+q_o} = \frac{q_w}{q_t} \Rightarrow \quad q_w = f_w q_t \quad \text{and} \quad q_o = q_t(1-f_w)$$

$$f_w = \frac{1+\frac{Ak_o}{\mu_o q_t}\cdot\left(\frac{dP_c}{dx} - \Delta\rho g \sin\alpha\right)}{1+\frac{\mu_w k_o}{\mu_o k_w}}$$

As P_c, k_o and k_w depend only on S_w, **f_w is a function of S_w only**

Simplification of fractional flow equation

- **Simplification assuming only viscous forces:**
  - Neglecting capillarity => $P_c = 0$

$$f_w = \frac{1-\frac{Ak_o}{\mu_o q_t}\cdot\Delta\rho.g.\sin\alpha}{1+\frac{\mu_w k_o}{\mu_o k_w}} = \frac{1-G}{1+\frac{\mu_w k_o}{\mu_o k_w}}$$

  with G the gravity term

$$G = \frac{Ak_o}{\mu_o q_t}\cdot\Delta\rho.g.\sin\alpha$$

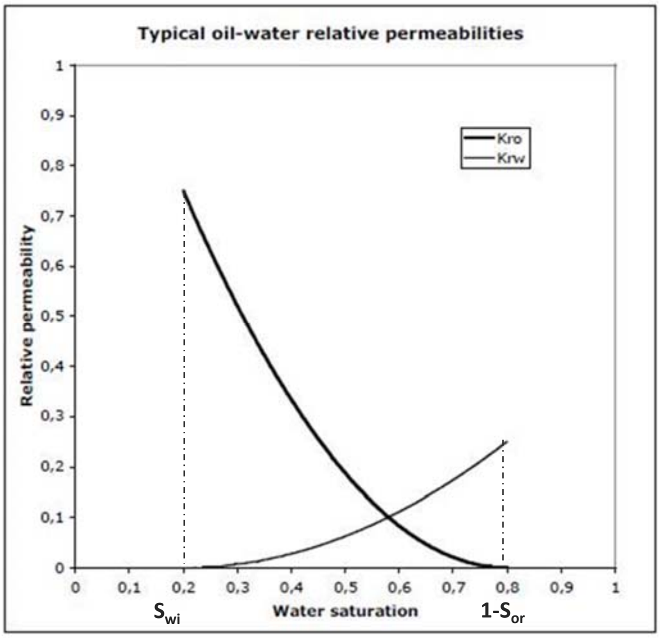
  - Neglecting gravity (horizontal reservoir or low dippage)

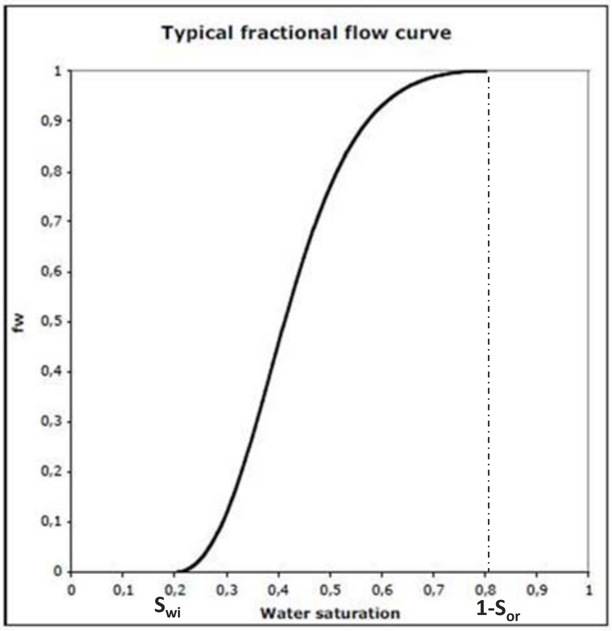
$$f_w = \frac{1}{1+\frac{\mu_w k_{row}(S_w)}{\mu_o k_{rw}(S_w)}}$$

  - In this latter case, $f_w(S_w)$ is calculated directly from $k_r(S_w)$ tables => a very easy way to evaluate the fractional flow f_w as a function of S_w

Fractional flow curve

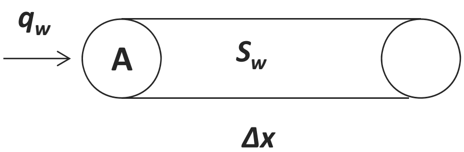
- **From the curves $k_r(S_w) - P_c(S_w)$, we derive the curve $f_w(S_w)$**





Buckley-Leverett equation

- **Considering a displacement of oil by water, the mass balance writes:**



$$[(q_w\rho_w)_x - (q_w\rho_w)_{x+dx}]\Delta t = A\emptyset\Delta x\left[(S_w\rho_w)^{t+\Delta t} - (S_w\rho_w)^t\right]$$

When $\Delta \mathbf{x} \rightarrow \mathbf{0}$ and $\Delta \mathbf{t} \rightarrow \mathbf{0}$, we get: $\frac{-\partial}{\partial x}(q_w\rho_w) = A\emptyset\frac{\partial}{\partial t}(S_w\rho_w)$

Assuming $\rho_w = c^{ste}$ and introducing $q_w = f_w q_t$ we get: $\frac{-\partial f_w}{\partial x} = \frac{A\emptyset}{q_t}\frac{\partial S_w}{\partial t}$

Since $f_w = f_w(S_w)$ we finally get the Buckley-Leverett equation:

$$\frac{-df_w}{dS_w}\frac{\partial S_w}{\partial x} = \frac{A\emptyset}{q_t}\frac{\partial S_w}{\partial t}$$

Constant saturation frontal advance equation

- **Since $S_w = S_w(x,t)$ and as we follow a fluid front of constant saturation, we get:**

$$dS_w = \frac{\partial S_w}{\partial x}dx + \frac{\partial S_w}{\partial t}dt = 0$$

- **Introducing this equation in the previous Buckley-Leverett equation, we get:**

$$\frac{dx}{dt} = \frac{q_t}{A\emptyset}\frac{df_w}{dS_w} = V(S_w)$$

=> the velocity of a front of a given saturation is constant

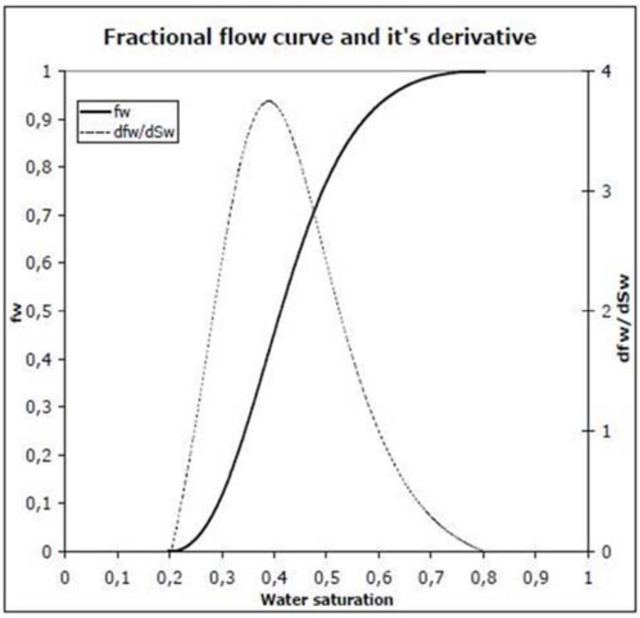
- **Integrating in time, we get:**

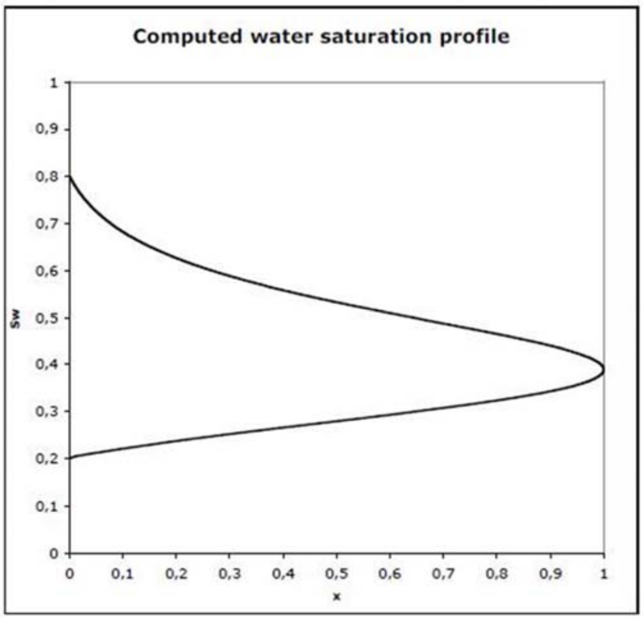
$$x_{S_w} = \frac{q_t \cdot t}{A\emptyset}\left(\frac{df_w}{dS_w}\right)_{S_w} = \frac{q_{inj} \cdot t}{A\emptyset}\left(\frac{df_w}{dS_w}\right)_{S_w} = \frac{W_{inj}}{A\emptyset}\left(\frac{df_w}{dS_w}\right)_{S_w}$$

where W_{inj} is the volume of water injected so far

Buckley-Leverett solution

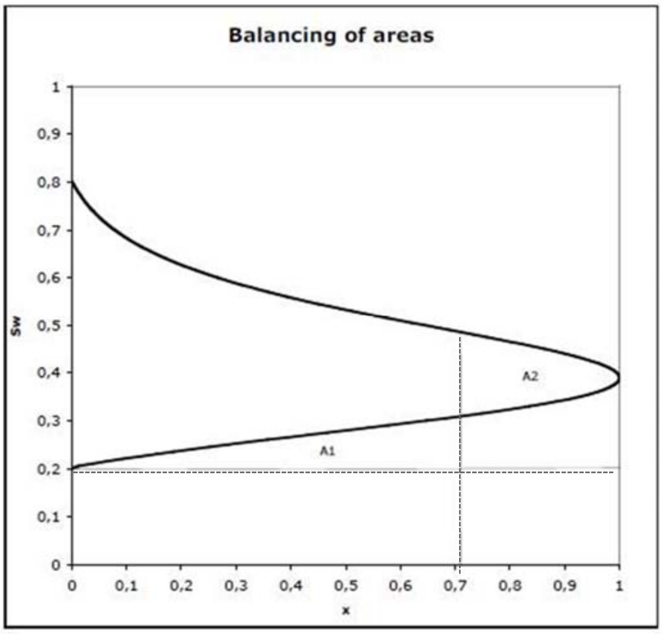
- **From $f_w(S_w)$ and its derivative, it is possible to get S_w vs. distance x**
  - The plot clearly displays an impossible physical situation with two different values of S_w for a given x (due to the presence of an inflexion point in the fractional flow curve)

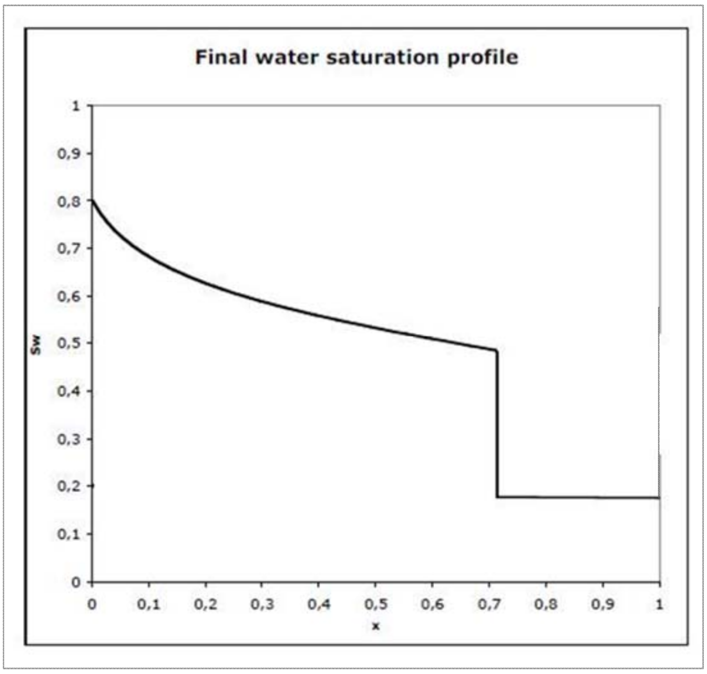




Buckley-Leverett solution - 2

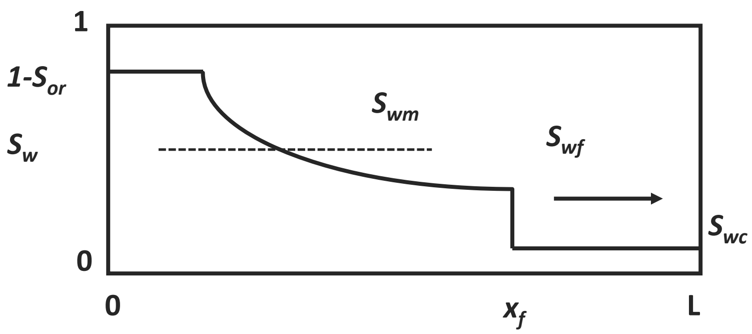
- **Buckley-Leverett solution consists in introducing a frontal discontinuity in $S_w(x)$**
  - The areas behind and before the front are balanced
  - Physical interpretation is that all the water injected remains behind the front



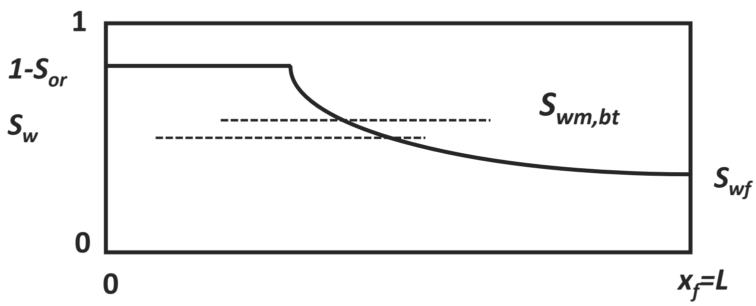


Situation before and at water breakthrough

Before breakthrough



At breakthrough



Water saturation at the front

- **In general, we can write**

$$x_f(S_{wf} - S_{wi}) = \int_{S_{wi}}^{S_{wf}} x.\,dS_w$$

- **From the previous equation we have:**

$$x_f = \frac{q_t \cdot t}{A\emptyset}\left(\frac{df_w}{dS_w}\right)_f \quad \Rightarrow \quad x_f(S_{wf} - S_{wi}) = \frac{q_t \cdot t}{A\emptyset}\left(\frac{df_w}{dS_w}\right)_f (S_{wf} - S_{wi})$$

- **Furthermore**

$$x = \frac{q_t \cdot t}{A\emptyset}\left(\frac{df_w}{dS_w}\right) \quad \Rightarrow \quad \int_{S_{wi}}^{S_{wf}} x.\,dS_w = \frac{q_t \cdot t}{A\emptyset}\int_{S_{wi}}^{S_{wf}} df_w = \frac{q_t \cdot t}{A\emptyset}\left(f_w(S_{wf}) - f_w(S_{wi})\right)$$

- **Therefore:**

$$\left(\frac{df_w}{dS_w}\right)_{S_{wf}} = \frac{f_w(S_{wf}) - f_w(S_{wi})}{S_{wf} - S_{wi}}$$

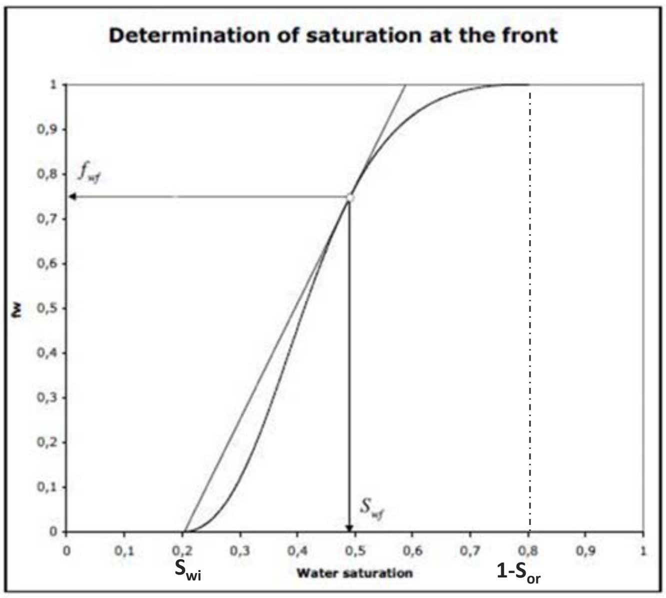
=> the slope of the tangent of the curve $f_w(S_w)$ at the point S_{wf} is equal to the slope of the chord joining the first point of the curve $f_w(S_w)$ (where it is assumed that $S_w = S_{wi}$) and this point => **graphical construction using Welge tangent**

Water saturation at the front - Welge tangent method

- **Welge tangent is the tangent at the curve $f_w(S_w)$ passing by the initial water saturation point**

- **The line passing by the point $(S_w = S_{wi}, f_w(S_{wi}) = 0)$ and tangent to the curve defines the water saturation at the front**

- **The Welge tangent allows to determine graphically the water saturation at the front (and corresponding fractional flow)**



Diffusive flow – Buckley-Leverett theory

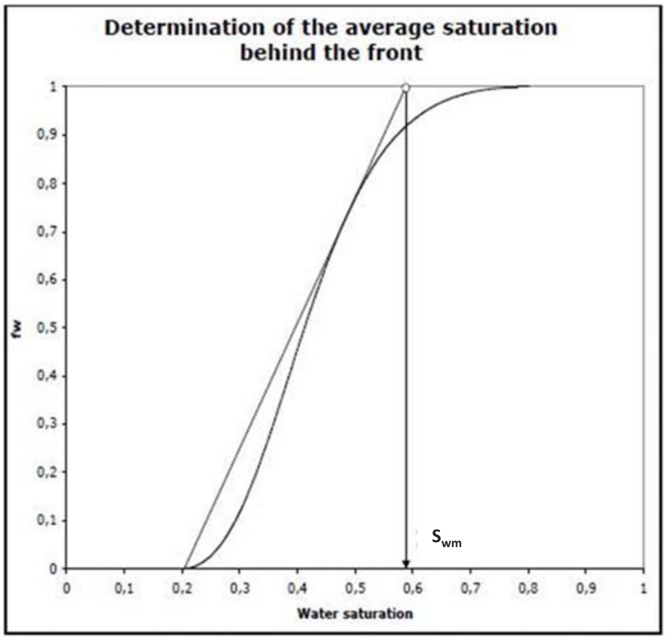
Average water saturation after the front

- **The calculation of the slope of the Welge tangent gives:**

$$\left(\frac{df_w}{dS_w}\right)_{S_{wf}} = \frac{1}{S_{wm} - S_{wi}}$$

where S_{wm} is the value of the average water saturation behind the front

- **The intersection of the Welge tangent with the line $f_w = 1$ gives the value of the average water saturation behind the front S_{wm}**



Diffusive flow – Buckley-Leverett theory

Oil recovery and time of water breakthrough

- **The oil recovery (in % of the pore volume) at breakthrough is given by:**

$$N_{pd,bt} = W_{id,bt} = S_{wm,bt} - S_{wi} = S_{wm} - S_{wi} = 1 \Big/ \left(\frac{df_w}{dS_w}\right)_{S_{wf}}$$

and

$$Rf = \frac{S_{wm} - S_{wi}}{1 - S_{wi}}$$

- **The velocity of the front is given by:**

$$V_f = \frac{q_t}{A\emptyset}\frac{\Delta f_w}{\Delta S_w} = \frac{q_t}{A\emptyset}\left(\frac{df_w}{dS_w}\right)_{S_{wf}} = \frac{q_t}{A\emptyset(S_{wm} - S_{wi})}$$

- **Given the distance L between the injector and producer wells , the time of breakthrough is:**

$$t_{bt} = \frac{L}{V_f} = \frac{LA\emptyset(S_{wm} - S_{wi})}{q_t} = \frac{LA\emptyset(S_{wm} - S_{wi})}{q_{inj}} = \frac{W_{inj}}{q_{inj}} = \frac{W_{id}}{q_{id}}$$

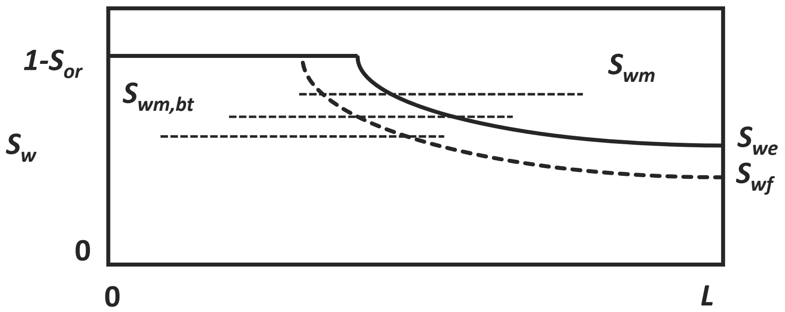
where W_{id} is the dimensionless injected water volume: $W_{id} = S_{wm} - S_{wi}$
and q_{id} is the dimensionless injected water flowrate: $q_{id} = q_{inj}/LA\emptyset$

Diffusive flow – Buckley-Leverett theory

Situation after water breakthrough

- At $x = L$, water saturation S_{we} increases over S_{wf} and fractional flow f_{we} increases
- We can still use Buckley-Leverett equation at $x = L$ and we get:

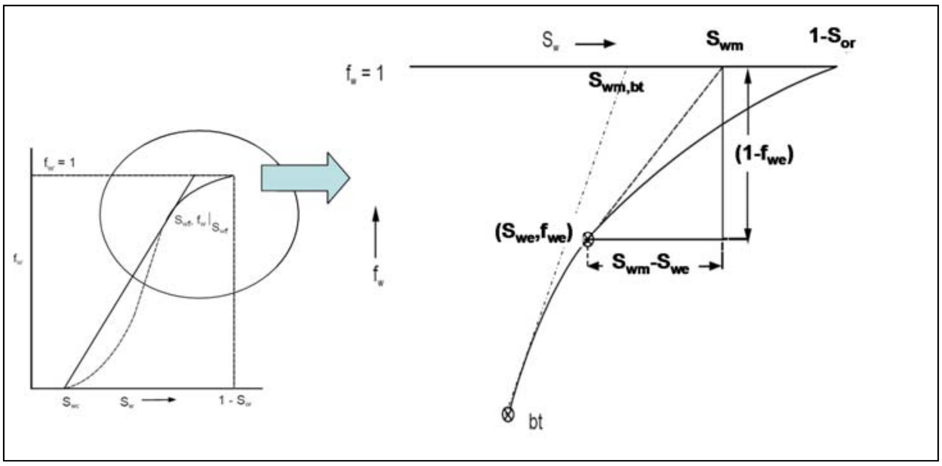
$$L = \frac{W_i}{A\emptyset}\left(\frac{df_w}{dS_w}\right)_{S_{we}}$$



Diffusive flow – Buckley-Leverett theory

Oil recovery after water breakthrough

- Given water saturation $S_{we} > S_{wf}$ and fractional flow f_{we} we may draw a Welge tangent and get the corresponding value of average water saturation S_{wm}



- The oil recovery (in % of the pore volume) is given by:

$$N_{pd} = S_{wm} - S_{wi} = (S_{wm} - S_{we}) + (S_{we} - S_{wi}) = (S_{we} - S_{wi}) + (1 - f_{we}) \cdot W_{id}$$

where W_{id} is the % of pore volume invaded given by: $W_{id} = \frac{W_i}{LA\emptyset} = 1/\left(\frac{df_w}{dS_w}\right)_{S_{we}}$

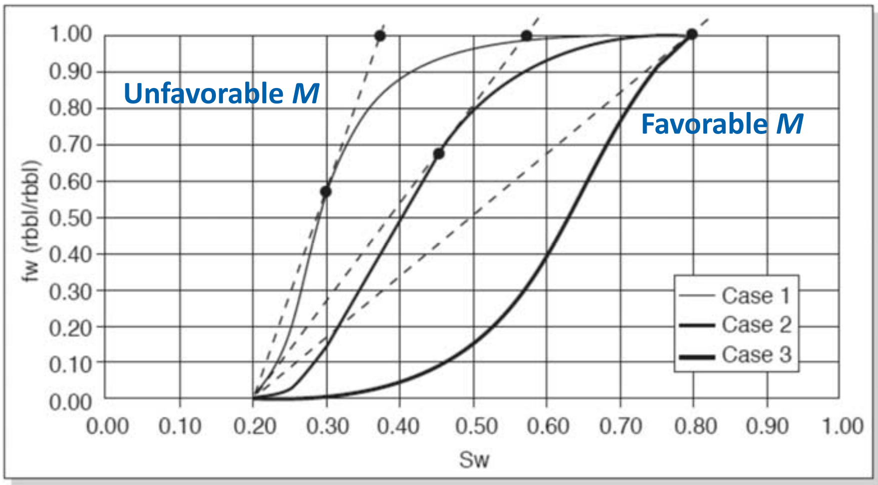
- The corresponding time (assuming constant injection rate) is:

$$t_{id} = \frac{W_{id}}{q_{id}} = \frac{LA\emptyset}{q_{inj}} \cdot 1/\left(\frac{df_w}{dS_w}\right)_{S_{we}}$$

Diffusive flow – Buckley-Leverett theory

Effect of the mobility ratio

- **Lower favorable values of the mobility ratio M shift the fractional flow curve to the right**
  - S_{wm} value is high, almost equal to the maximum water saturation
  - Most of the oil has been recovered at the breakthrough
- **Higher unfavorable values of the mobility ratio M shift the curve to the left**
  - S_{wm} value is low, far from the maximum water saturation
  - Large quantities of oil remain behind the front



Reminder: simplified fractional flow equation is:

$$f_w = \frac{1}{1+\frac{\mu_w k_{row}(S_w)}{\mu_o k_{rw}(S_w)}} = \frac{1}{1+1/M} = \frac{M}{M+1}$$

Diffusive flow – Buckley-Leverett theory

Effect of gravity and flow rate

- **Gravity**
  - Fractional flow equation shows that the gravity term will have a positive effect for oil displacement when $0 < \alpha < \pi$ i.e. in the up dip direction and negative effect when $\pi < \alpha < 2\pi$ i.e. in the down dip direction
  - => the fractional flow of water for displacement in the up dip direction is lower than for displacement in the down dip direction since, in the first case, gravity tends to suppress the flow of water
  - => up dip is favorable to the displacement of oil by water

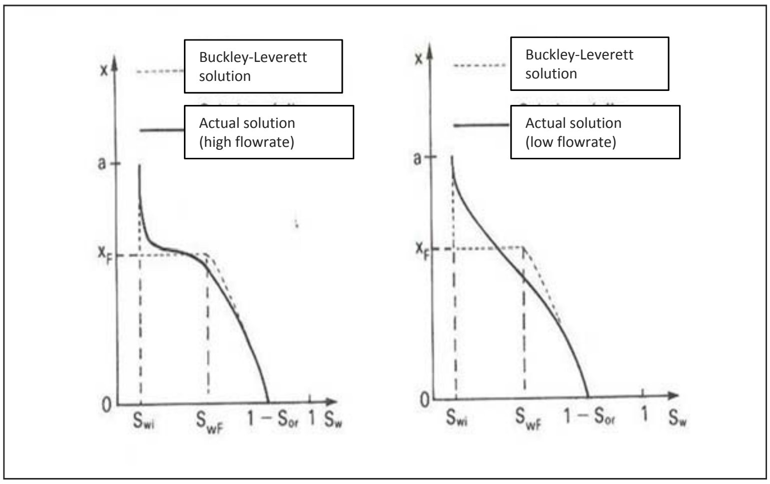
- **Rates**
  - The fractional flow equation shows that the fractional flow f_w decreases with decreasing rates

=> low rates are favorable for displacement of oil by water

=> slow production should be preferred

Effect of capillary pressure

- The fractional flow equation shows that high capillary pressures lead to higher values of f_w that are unfavorable to oil displacement
- However, at the front, high capillary forces tend to smooth the sharp solution resulting from Buckley-Leverett method
- => The higher the flow rate, the closer the profile obtained by BL theory approaches the true profile
- => In general, velocities in the reservoir are slow but the capillary forces can still be neglected



Some ratio of interest

- **Fractional flow or water-cut**

$$f_w = \frac{q_w}{q_w + q_o} = \frac{1}{1 + \dfrac{\mu_w k_{row}(S_w)}{\mu_o k_{rw}(S_w)}} = 1 - f_o$$

- **Surface water-cut**

$$F_w = \frac{Q_w}{Q_w + Q_o} = \frac{q_w/B_w}{q_w/B_w + q_o/B_o} = \frac{f_w}{f_w + \dfrac{B_w}{B_o}(1 - f_w)}$$

- **Water-Oil Ratio**

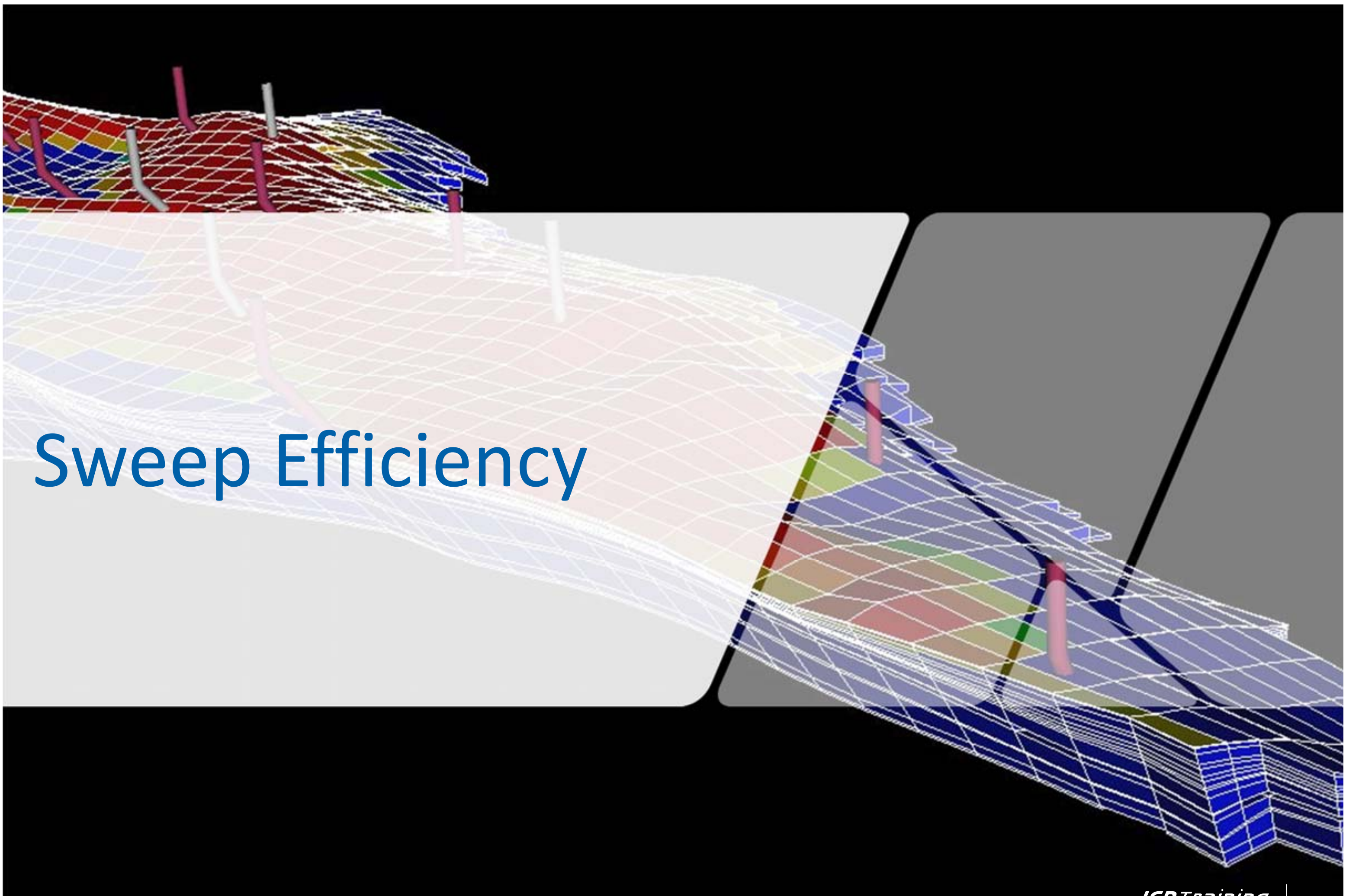
$$WOR = \frac{Q_w}{Q_o} = \frac{q_w/B_w}{q_o/B_o} = \frac{f_w}{1 - f_w} \cdot \frac{B_o}{B_w}$$

- **Gas-Oil Ratio**

$$GOR = \frac{Q_g}{Q_o} = R_s + \frac{f_g}{1 - f_g} \cdot \frac{B_g}{B_o}$$

Diffusive flow – Buckley-Leverett theory

- **Displacement of oil in the reservoir by water (or gas) is modeled through the assumption of so-called diffusive flow i.e. linear immiscible incompressible under vertical equilibrium**
- **Buckley-Leverett theory provides a simplified solution for unidirectional displacement disregarding capillarity**
- **Buckley-Leverett allows to calculate the fractional flow (also named water-cut) f_w as a function of water saturation S_w**
- **Using the Welge tangent method, one can easily access to:**
  - The estimate of the water saturation at the front S_{wf}
  - The estimate of the mean water saturation behind the front S_{wm} hence to the mean oil saturation after the front and corresponding oil recovery
  - The estimate of the velocity of the front of constant water saturation V_f hence the time of water breakthrough



Sweep Efficiency

Definition

- **The sweep efficiency is defined as the recovery factor in reservoir conditions for the area that has been flooded:**

$$E = \frac{N_p B_o}{V_p S_{oi}}$$

where S_{oi} is the oil saturation at the start of injection

- **The sweep efficiency can be expressed by:**

$$E = E_A . E_Z . E_D$$

Where:

$\mathbf{E_A}$ is the areal sweep efficiency

$\mathbf{E_Z}$ is the vertical (or invasion) efficiency

$\mathbf{E_D}$ is the displacement (or microscopic i.e. at the pore scale) efficiency

- **E is typically in the range 25-60%**

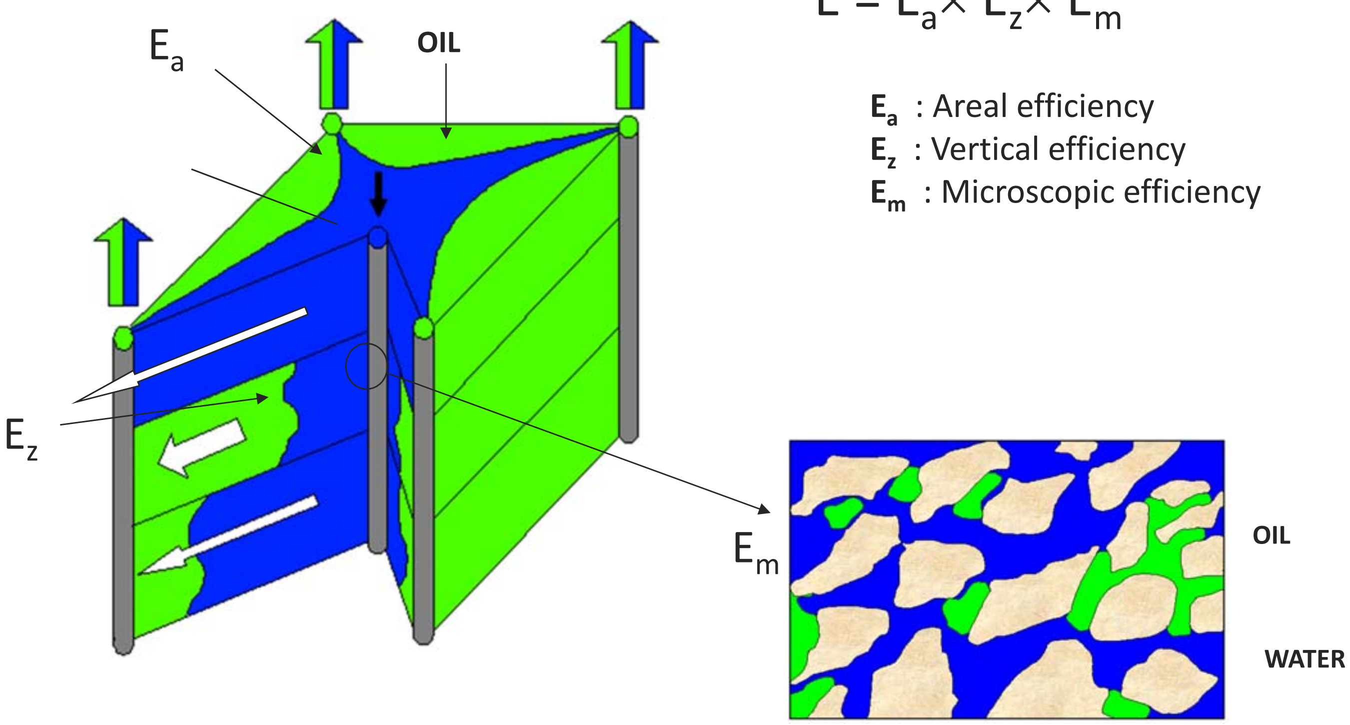
Concept illustration for water flooding

$$E = E_a \times E_z \times E_m$$

$\mathbf{E_a}$: Areal efficiency

$\mathbf{E_z}$: Vertical efficiency

$\mathbf{E_m}$: Microscopic efficiency

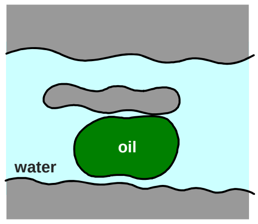


Sweep efficiency

Definitions

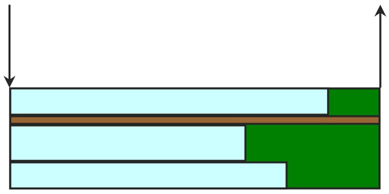
- **Displacement efficiency:**

$$E_D = \frac{S_{oi} - S_{or}}{S_{oi}} = \frac{1 - S_{wi} - S_{or}}{1 - S_{wi}}$$



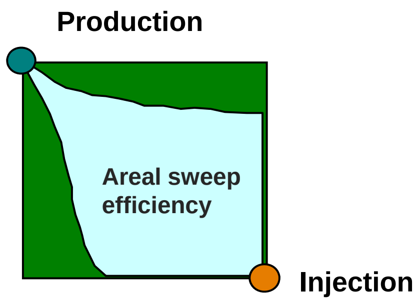
- **Vertical efficiency:**

$$E_z = \frac{vertical\ area\ swept}{total\ vertical\ area}$$



- **Areal (superficial) efficiency:**

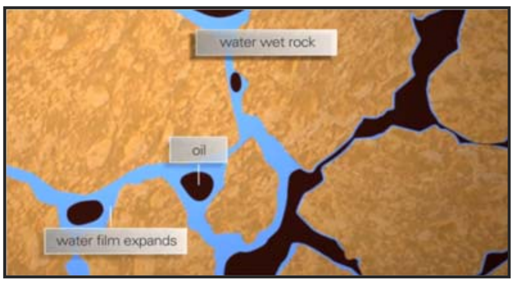
$$E_a = \frac{horizontal\ area\ swept}{total\ horizontal\ area}$$

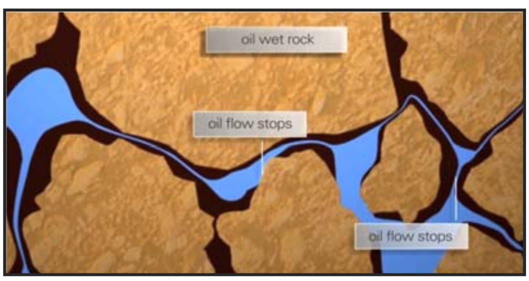


Sweep efficiency

Displacement efficiency

- **The displacement efficiency at the pore scale depends on:**
  - Wettability
  - The capillarity effects and porous network
  - The mobility ratio: relative permeability & viscosity





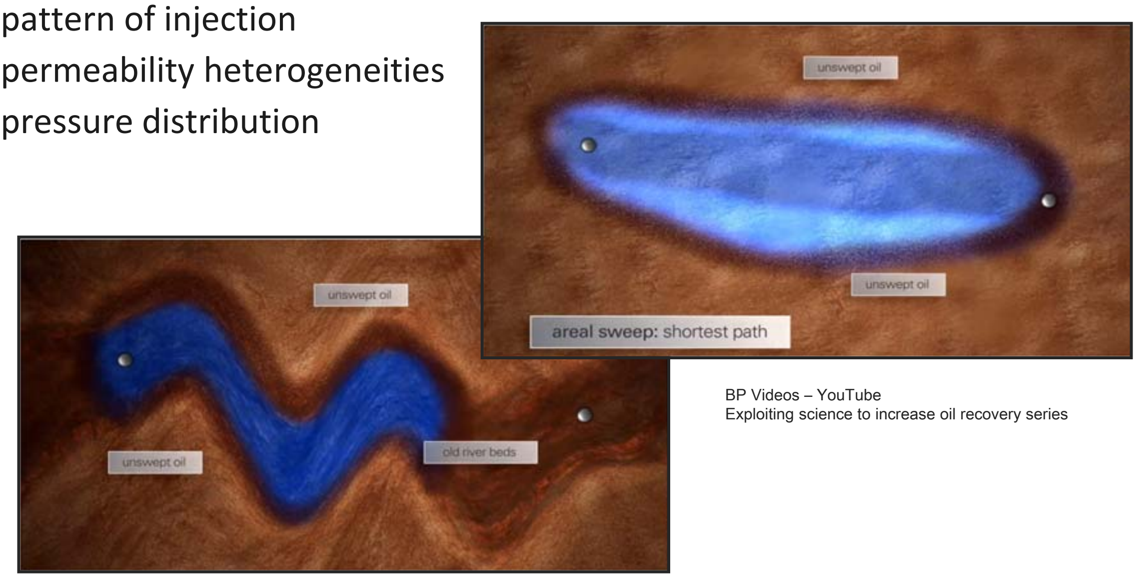
BP Videos – YouTube
Exploiting science to increase oil recovery series

In water-wet systems, at the pore scale, oil can be trapped in the center of the pores while water is flowing around. Oil that is connected to flow paths continues to be displaced.
In oil-wet systems, oil may still be connected to flow paths but there may be large flow of water at the center of the pores.

Sweep efficiency

Areal efficiency

- **The areal efficiency depends on:**
  - The mobility ratio: relative permeability & viscosity
  - The pattern of injection
  - The permeability heterogeneities
  - The pressure distribution



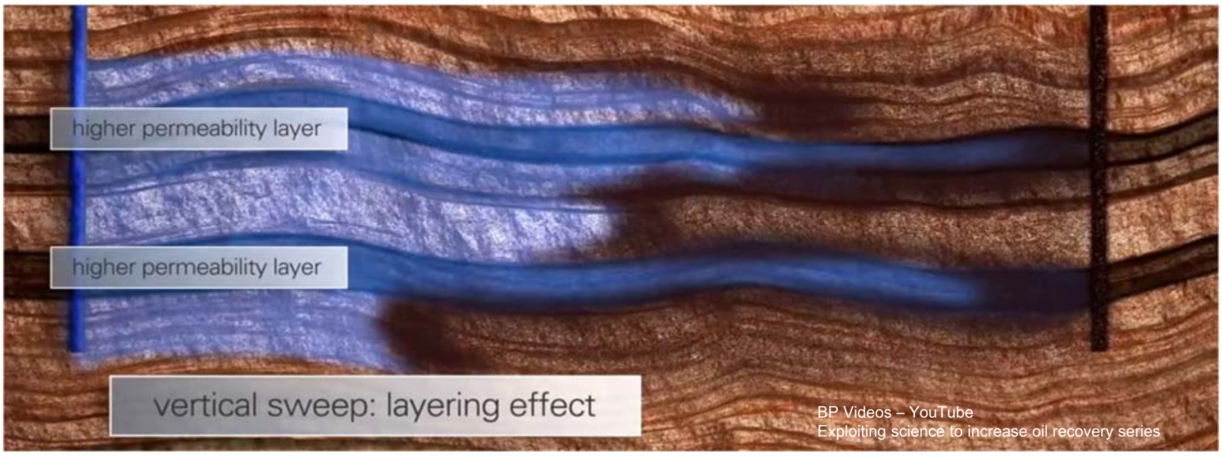
BP Videos – YouTube
Exploiting science to increase oil recovery series

Oil can be bypassed because of the ineffectiveness of the macroscopic sweep. A pattern flood can be affected by a heterogeneous formation (especially anisotropic permeability i.e. preferential direction for permeability) or by the development of fingering/tongues because of a contrast of viscosity/mobility

Sweep efficiency

Vertical efficiency

- **The vertical efficiency depends on:**
  - The rock property variation between different flow units especially vertical distribution of permeability



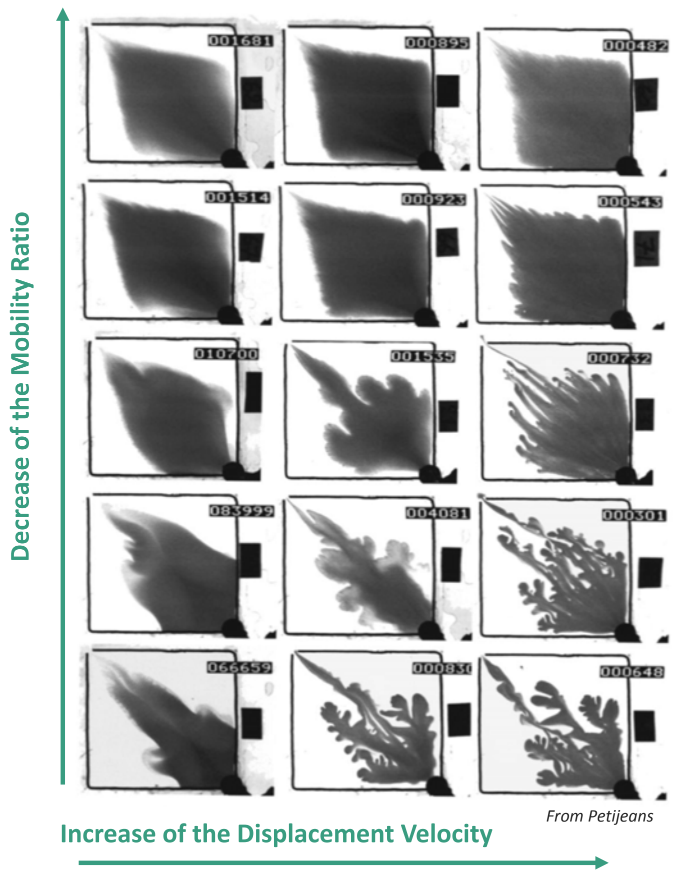
The vertical sweep can be affected by viscous fingering, as well as by the preferential movement of fluids along a high-permeability thief zone or by gravity override of injection gas or underride of injection water.

Sweep efficiency - Fingering

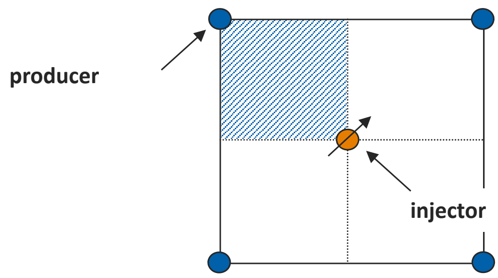
- The Buckley-Leverett frontal advance theory assumes that the initial displacement of oil by water occurs as a smooth, substantially straight interface.
- In 1951, Engelberts and Klinkenberg showed that, in scaled experiments, the existence of fingers, or discrete streamers of displacing water moving through the oil, could be inferred. Later van Meur demonstrated the existence of these fingers by a clever experimental technique. He showed that even in laboratory systems where care is taken to insure as nearly uniform porous media as possible, the tendency for these fingers to form increases as the oil-water viscosity ratio increases.
- Later work by other investigators showed that at high oil-water viscosity ratios, there are instabilities at the oil-water interface and these instabilities grow until their effect is dominant on the overall flooding performance.
- Debates raged over the practical significance of these fingers. An otherwise peaceful gathering of production research engineers could be turned into a heated controversy by the question, "Do you think viscous fingers are solely a laboratory phenomenon?
- The actual reservoir having complex variations in permeability and porosity a macroscopically non uniform flood front very much similar to viscous fingering will occur, if from no other cause than the non uniformities in rock permeabilities.
- A practicing reservoir engineer would term this the effect of reservoir heterogeneities.

Sweep efficiency

5-spot areal efficiency



From Petijeans



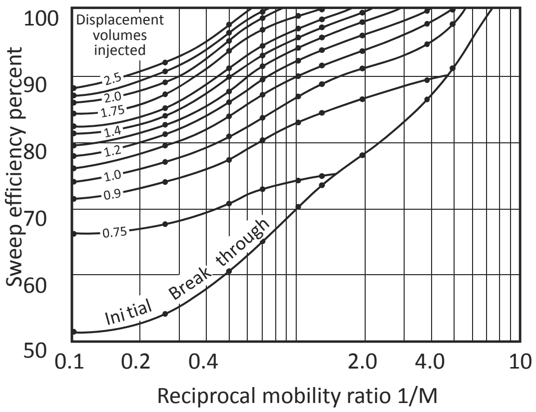
- **The superficial efficiency increases when :**
  - the mobility ratio decreases
  - the velocity of the displacement decreases

Sweep efficiency

5-spot areal sweep efficiency and mobility ratio

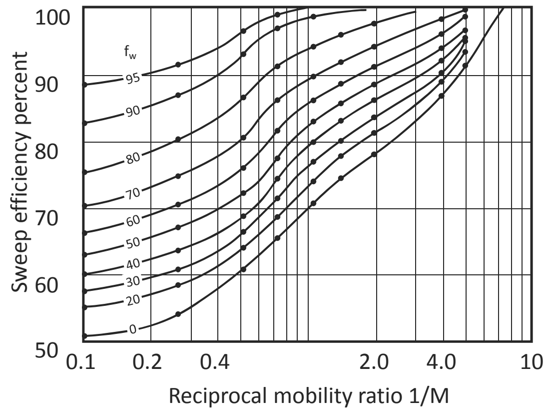
Sweep efficiency for the five-spot pattern as a function of volumes injected and mobility ratio $M = \gamma_w/\gamma_o$

after Dyes, Caudle, and Erickson, Trans. AIME



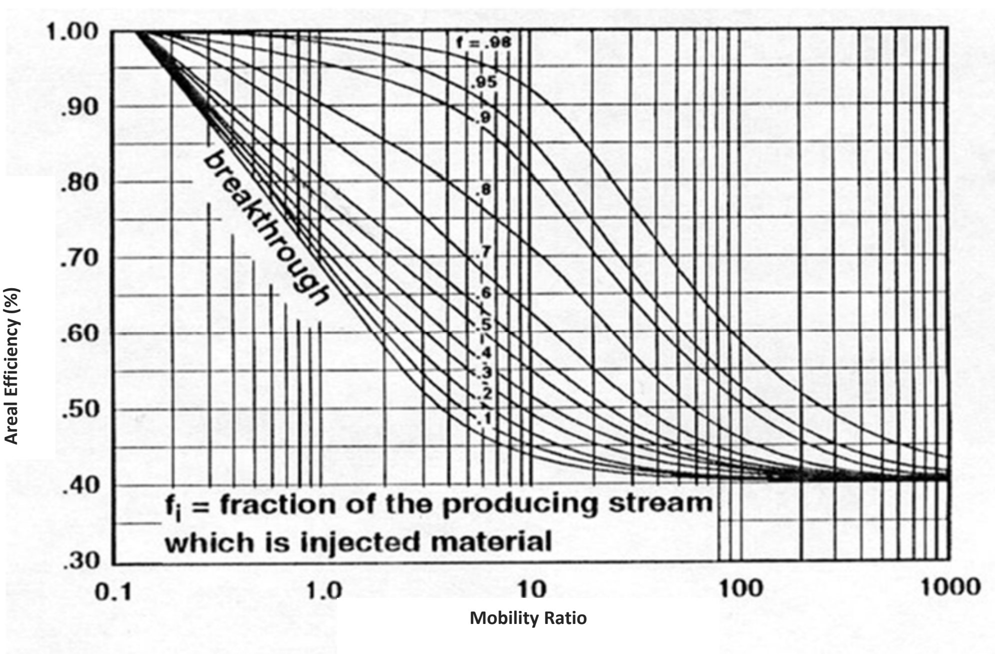
Sweep efficiency for the five-spot pattern as a function of fractional flow f_w and mobility ratio $M = \gamma_w/\gamma_o$

after Dyes, Caudle, and Erickson, Trans. AIME



Sweep efficiency

5-spot areal sweep efficiency and mobility ratio



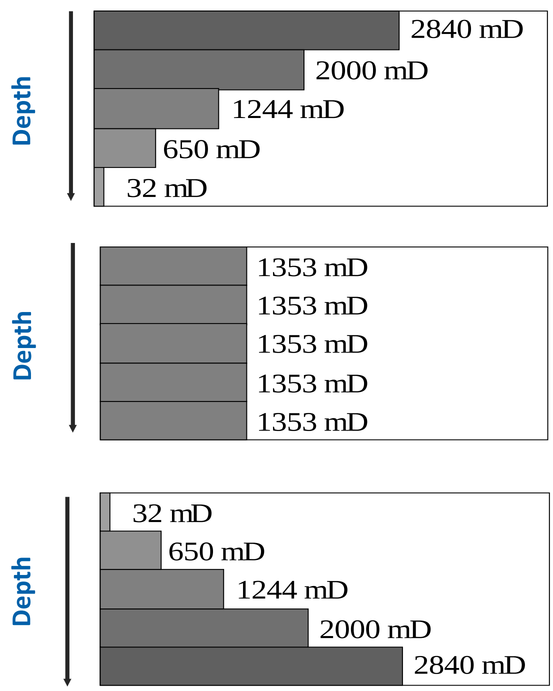
From Caudle

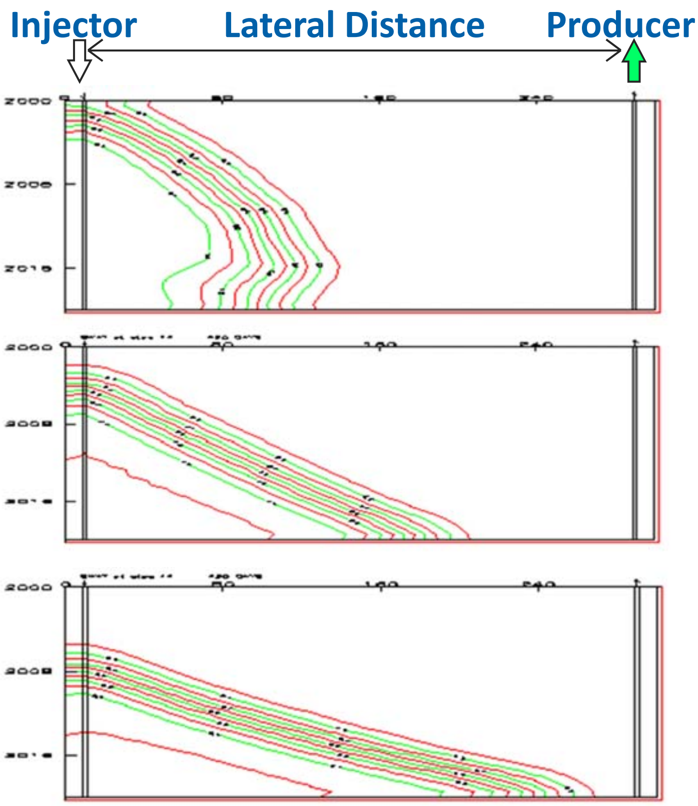
At breakthrough (i.e. when the displacing fluid breaks at the well i.e. $f = 0$) it can be seen that $E_A = 0.7$ for $M = 1$ while $E_A \rightarrow 0.4$ for $M > 1000$

Sweep efficiency

Effect of vertical permeability distribution

Kv/Kh = 1





Sweep efficiency

Effects of vertical permeability distribution - 2

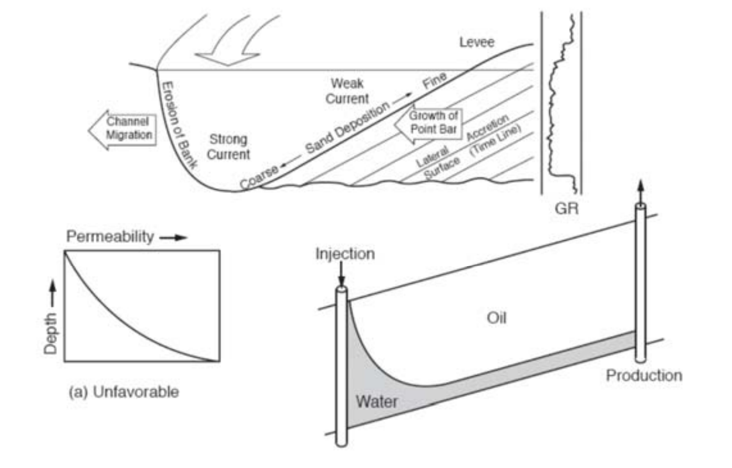


Figure 45 Effect of unfavourable permeabilty distrubution in waterflooding (Archer[11])

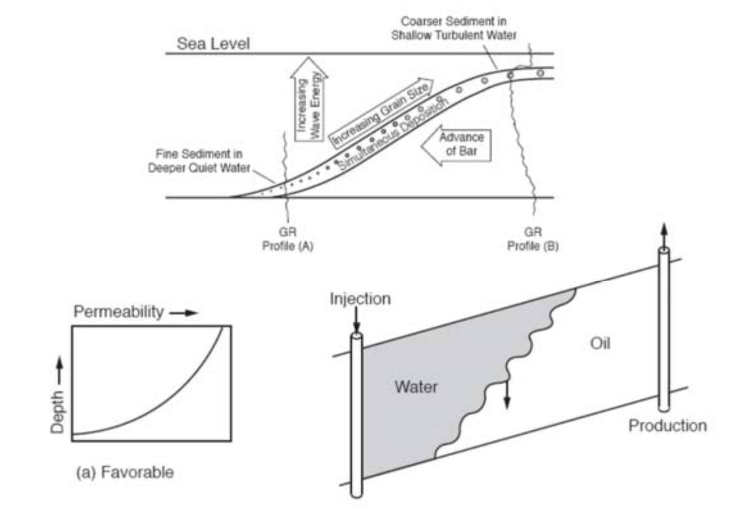
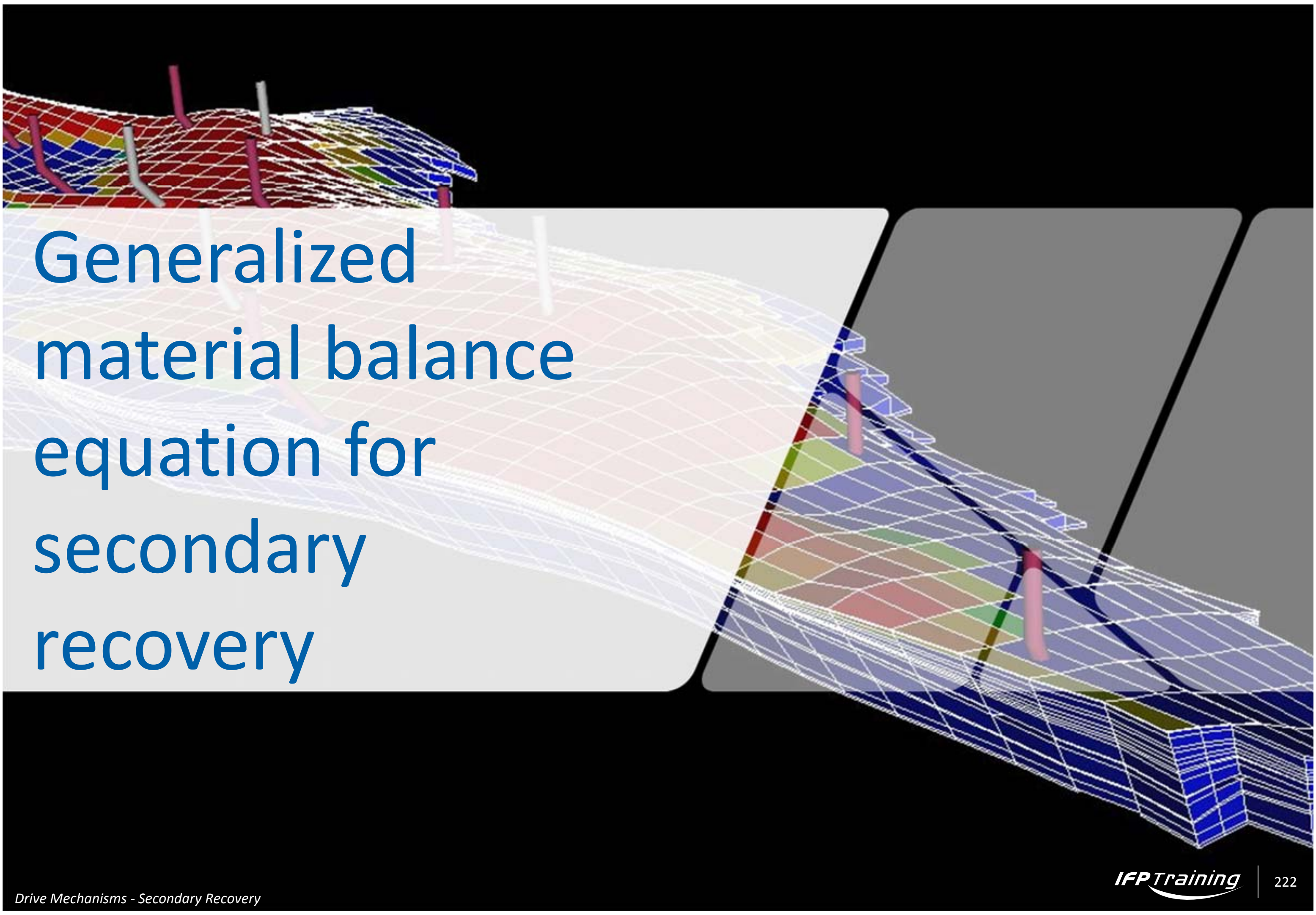


Figure 46 Effect of favourable permeabilty distrubution in waterflooding (Archer[11])

Sweep efficiency

- **Sweep efficiency is defined as the recovery factor at reservoir conditions for the area that has been flooded**
- **It is separated in three terms:**
  - Microscopic or displacement efficiency related to the pore scale
  - Areal efficiency and vertical efficiency related to the flooding
- **Microscopic efficiency depends on the initial water saturation and the residual oil saturation**
- **Areal efficiency depends on the mobility ratio and the water cut**
- **Vertical efficiency depends mostly on vertical permeabilities and vertical distribution of permeabilities; due to heterogeneities, it is most difficult to calculate and is therefore very often estimated through reservoir simulation**
- **Sweep efficiency is typically in the range 25-60%**

Generalized material balance equation for secondary recovery



Generalized material balance

Oil reservoirs generalized MBE with water/gas injection

$NB_{oi} =$	**initial oil volume**
$(N - N_p)B_o$	**oil volume left in the reservoir with its dissolved gas**
$+[NR_{si} - (N - N_p)R_s - G_p]B_g$	**volume of gas released from oil and staying in the reservoir**
$+mNB_{oi}(B_g/B_{gi} - 1)$	**volume of gas from the initial gas cap invading the oil zone**
$+W_e$	**water entry from the aquifer**
$-W_pB_w$	**produced water**
$+W_{inj}B_{winj}$	**injected water**
$+G_{inj}B_{ginj}$	**injected gas**

With $R_p = G_p/N_p$ the average produced GOR

And $B_t = B_o + (R_{si} - R_s)B_g$ the total or two-phase formation volume factor

Generalized material balance

Drive index

Introducing R_p within the previous equation and rearranging the terms:

$$N_p[B_o + (R_p - R_s)B_g] = N[(B_o - B_{oi}) + (R_{si} - R_s)B_g] + mNB_{oi}[B_g/B_{gi} - 1] + W_e - W_pB_w + W_{inj}B_{winj} + G_{inj}B_{ginj}$$

- **Introducing $D = N_p[B_o + (R_p - R_s)B_g] = N_p[B_t + (R_p - R_{si})B_g]$ and dividing by D we get:**

$$1 = \frac{N(B_t - B_{ti})}{D} + \frac{mNB_{oi}[B_g/B_{gi} - 1]}{D} + \frac{W_e - W_pB_w}{D} + \frac{W_{inj}B_{winj}}{D} + \frac{G_{inj}B_{ginj}}{D}$$

$$1 = DDI + SDI + WDI + IDI$$

DDI	SDI	WDI	IDI
Depletion Drive Index	Segregation Drive Index	Water Drive Index	Injection Drive Index

Injection drive index

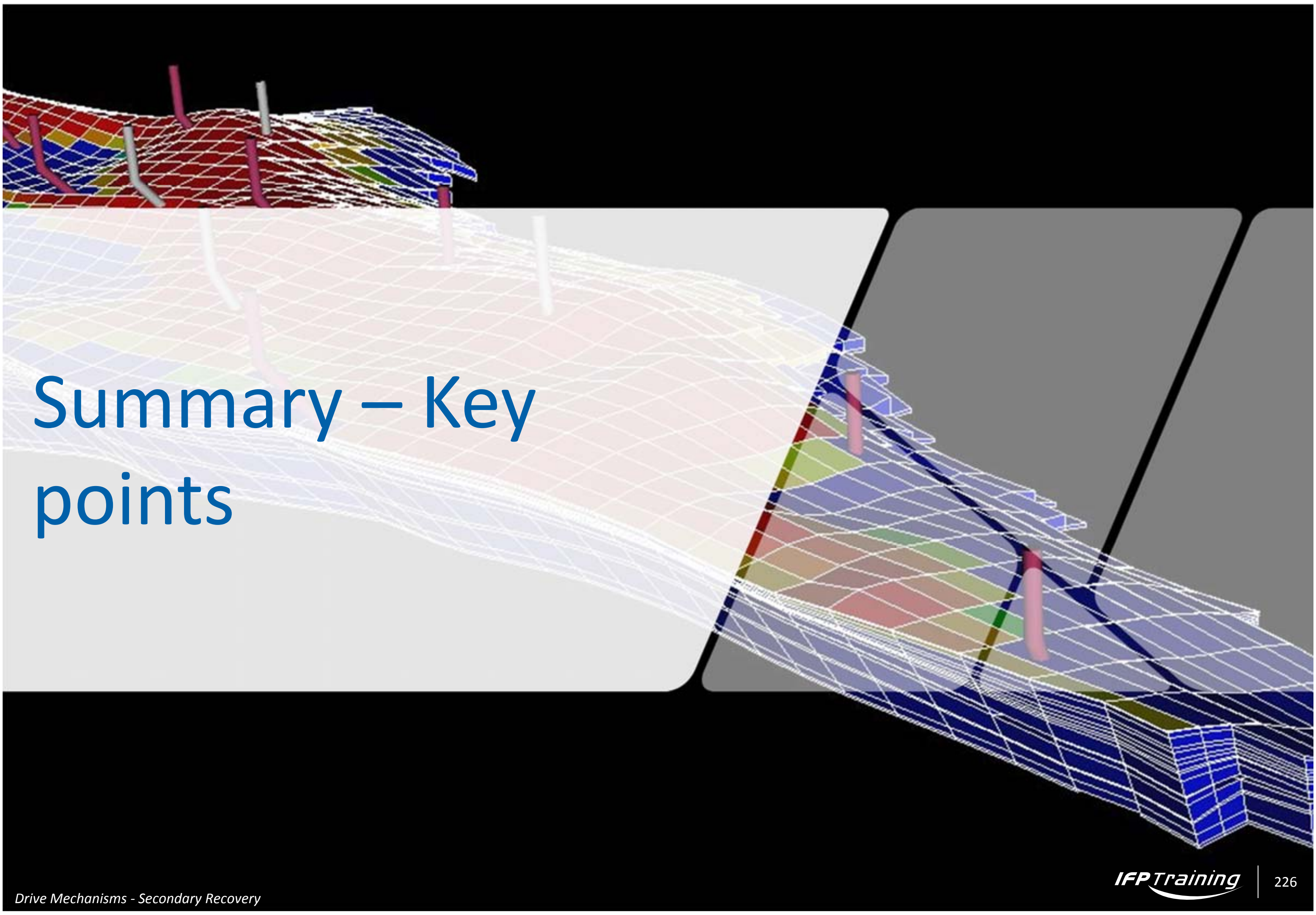
- **By definition**

$$IDI = \frac{W_{inj}B_{winj}}{D} + \frac{G_{inj}B_{ginj}}{D}$$

where

$$D = N_p\left[B_o + \left(R_p - R_s\right)B_g\right] = N_p\left[B_t + \left(R_p - R_{si}\right)B_g\right]$$

IDI allows to compare the relative importance of injecting water and/or gas as a drive mechanism by respect to the other natural drive mechanisms of the reservoir



Summary – Key points

Secondary recovery

- Secondary recovery aims to improve oil recovery when natural drive mechanisms are not efficient enough i.e. when there is no strong natural water drive
- It consists in supporting pressure and sweeping the remaining oil in the reservoir by injecting fluid, either water or gas
- Secondary recovery implies multiphase flow in the reservoir that has to be controlled in order to get a high sweep efficiency
- Sweep efficiency is the Rf at reservoir conditions and for the flooded area; it is divided into the microscopic efficiency, areal efficiency and vertical efficiency
- Sweep efficiency depends on multiple parameters among which the mobility ratio M: if $\mathrm{M} > 1$, it is unfavorable, if $\mathrm{M} < 1$, it is favorable
- Sweep efficiency is typically in the range 25-60%

Secondary Recovery

- Feasibility studies are mandatory before performing a secondary recovery
- Economics will decide on the type of secondary recovery to be used
  - It is necessary to show an increase in the reserves associated with good economics
  - The impact on the surface facilities (pumping/compressing and treatment) has to be assessed
- The natural drive mechanisms have to be identified as soon as possible
- The distribution of heterogeneities in the reservoir, especially regarding permeability, have to be understood and modeled through reservoir modeling and simulation
- Extensive laboratory tests have to be done
  - SCAL (wettability, Kr's, Pc)
  - Water flooding and gas flooding at reservoir conditions
  - Water compatibility issues
  - Studying clay swelling issues
  - Fine mobilization issues

Water injection

- **Water injection is the most commonly used secondary recovery process especially because of water availability**
- **The mobility ratio may be favorable, especially for medium oil and it is, in any case, less unfavorable then for gas injection; however residual oil saturation may remain high**
  - Density contrast is lower than for gas injection but high dip reservoir may favor gravity drainage and stabilization of the injection front
- **A good knowledge of the reservoir is mandatory:**
  - Water/oil contact: injection should be done in the water zone for a better injectivity or at least near the contact
  - Permeability heterogeneities especially vertical permeability heterogeneities
- **The recovery factor can be as high as 50-60%**

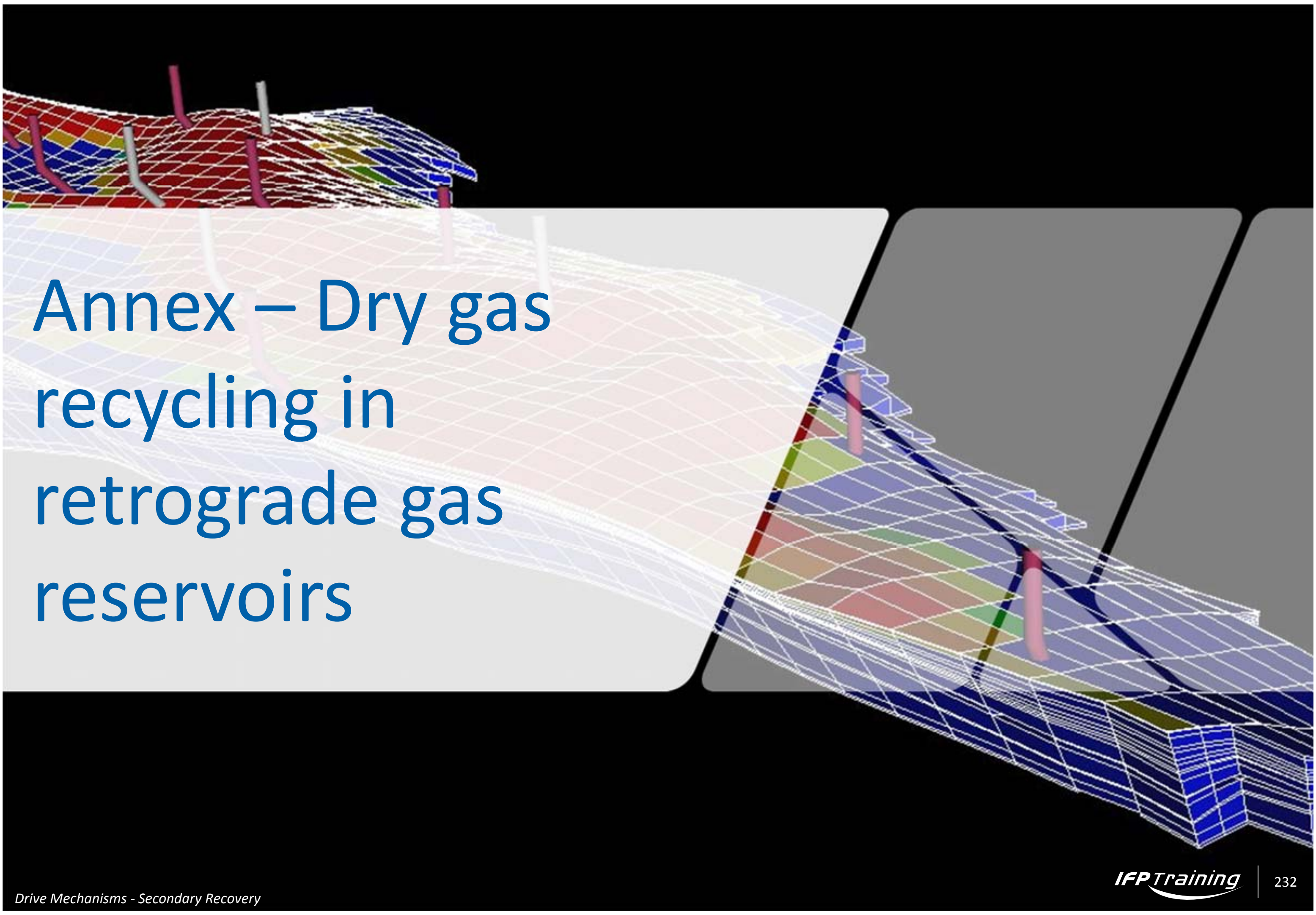
Gas injection

- **Gas injection is less used than water injection mainly because of gas availability and because of the cost of surface facilities (compressor)**
  - The mobility ratio is always unfavorable for gas injection, instabilities develop quickly but oil residual saturation is lower after gas flooding than after water flooding, and a higher mobility of gas allows to flood areas remained unswept by water
  - Density contrast is higher and may favor gravity drainage and stabilization of the injection front
  - Immiscible gas injection can be turned to miscible gas injection with even lower residual oil saturation (possibly nil when miscibility is effectively reached)
- **A good knowledge of the reservoir is mandatory:**
  - Gas/oil contact: injection should be done close to the contact if any
  - Permeability heterogeneities especially vertical permeability heterogeneities
  - A high dip reservoir may further favor gravity drainage
- **The recovery factor can be as high as 60-70% especially in case of gas gravity displacement**

Recovery factors

- **Natural drainage mechanisms for oil reservoirs:**
  - Monophasic expansion: Rf is a few %
  - Solution gas drive: Rf 10-25 %
  - Gas cap drive: Rf 25-40 %
  - Natural water drive: Rf 40-60 %
  - Compaction drive: Rf 0-20 %

- **Secondary recovery in oil reservoirs:**
  - Water injection: Rf up to 40-60%
  - Gas injection (gravity displacement) : Rf up to 60-70% (see EOR)



Annex – Dry gas recycling in retrograde gas reservoirs

Principle of dry gas recycling - 1

Retrograde condensate gas reservoir

- In these reservoirs, when the pressure drops below dew point pressure, some liquid forms in the reservoir especially at the vicinity of the wells => **phenomenon of condensate banking/blocking**
- Lower recovery for the liquid since a large part of it remains immobile in the reservoir due to a generally high value of critical condensate saturation
- Lower recovery for the gas since the presence of the immobile liquid at the vicinity of the well disturbs the flow of gas

One solution: dry gas recycling

- After separation at surface, all or part of the dry gas is reinjected in order to maintain pressure above the dew point
  - Reinjection of all of the dry gas: full recycling
  - Reinjection of part of the dry gas: partial recycling
- Process is miscible but can still be modeled through black-oil modeling (oil & gas) if pressure does not fall below the dew point

Principle of dry gas recycling - 2

Full recycling

- All the dry gas is reinjected but condensates are sold => deficiency in the material balance leading to a decline in pressure
- Main economic parameter: initial condensate yield above the dew point $\boldsymbol{r_{si}}$
- Recycling stops when the dry gas breaks at the well and the condensate production rate cannot sustain the required economics => blow-down and shift of sales towards dry gas
- Dry gas injection may also limit water entries in case of an active aquifer thus limiting the quantity of gas trapped behind the front

Partial recycling

- Typically reinjection of dry gas in excess of gas sales contract (e.g. during summer periods)
- However a limited pressure maintenance may improve the recovery of condensates and gas and limit water entries if any

Dry gas recycling

Mobility ratio

- **By definition**

$$M = \frac{k_{rgdmax}}{\mu_d} \Big/ \frac{k_{rgwmax}}{\mu_g}$$

- **Relative permeability**
  - Wet gas displacement by dry gas is a miscible process and IFT is nil

=> $S_{rgw} = 0$ in the pores contacted by the dry gas

=> $k_{rgdmax} = k_{rgwmax} = 1$

- **Viscosity**
  - $\mu_{gd} < \mu_{gw}$ but of the same order of magnitude typically 0.02 and 0.03 cP

- **As a consequence, M is always slightly higher than 1 but the process remains quite stable at macroscopic scale**

Dry gas recycling

Gravity effect

- **The table below shows the typical properties of dry and wet gas**

	Wet gas	Dry gas
Gravity, γ_g (air = 1)	0.937	0.672
Pseudo-critical temperature [2], T_c (ºR)	426	374
Pseudo-critical pressure [2], p_c (psia)	641	663
Z-factor at initial presure	0.894	0.936
Gas expansion factor at p_i, E_i (scf/rcf)	267	255
Gas FVF at p_i, B_{gi} (rcf/scf)	0.00375	0.00392
Gas density in the reservoir (lb/cu.ft)	19.1	13.1

  - $FVF_{gd} > FVF_{gw}$ => this property allows to compensate for the effect of removing the condensate on the material balance
  - $\rho_{gd} < \rho_{gw}$ => since M is slightly unfavorable, the stability of the displacement will strongly depend on the heterogeneities in the reservoir and especially the distribution of vertical permeability
  - A favorable case is coarsening downwards i.e. higher values of the permeability at the bottom

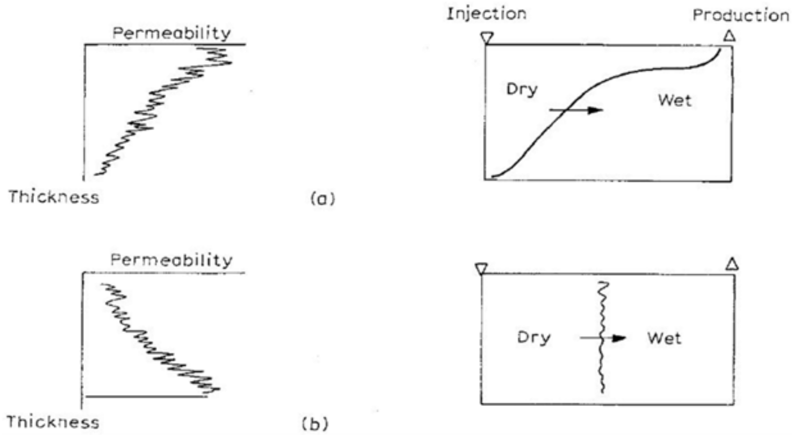
Dry gas recycling

Vertical equilibrium

- **With no restriction of vertical fluid movement across the reservoir, segregation occurs with lighter dry gas rising up to the top of the section**

Coarsening upward of permeability will produce an early breakthrough of the dry gas and result in a poor sweeping efficiency => recovery should be low despite miscibility and large quantities of dry gas will have to injected

Coarsening downward of permeability will produce a very efficient piston-like displacement across the reservoir



Dry gas recycling

Pseudo-relative permeabilities

- **Despite miscibility, calculating pseudo-relative permeabilities in order to solve the displacement of the wet gas by the dry gas is still valid**
- **In the case of N layers (ranging from top):**
  - The average is done after the $\boldsymbol{n}$ first layers (from top) have been flooded
  - Each layer is assumed to have been completely flooded with a final dry gas saturation of $\mathbf{1} - \boldsymbol{S_{wc_i}}$ (i.e. residual saturation in wet gas is nil) or not to have been flooded at all

  - Thickness averaged water saturation is:

$$\bar{S}_{gd_n} = \sum_{i=1}^{n} h_i \phi_i (1 - S_{wc_i}) / \sum_{i=1}^{N} h_i \phi_i$$

  - Thickness averaged relative permeability to dry gas is:

$$\bar{k}_{rgd_n} = \sum_{i=1}^{n} h_i k_i k_{rgdmax} / \sum_{i=1}^{N} h_i k_i$$

  - Thickness averaged relative permeability to wet gas is:

$$\bar{k}_{rgw_n} = \sum_{i=n+1}^{N} h_i k_i k_{rgwmax} / \sum_{i=1}^{N} h_i k_i$$

Dry gas recycling

Vertical efficiency

- **Principle**
  - The generation of pseudo (averaged) relative permeabilities makes the displacement one-dimensional
  - Buckley-Leverett theory and Welge tangent approach are suitable => the fractional flow is given by:

$$\bar{f}_{gd} = \frac{1 - \dfrac{A\bar{k}\bar{k}_{rgw}}{\mu_{gw} q_t} \cdot \Delta\rho . g . \sin\theta}{1 + \dfrac{\mu_{gd}}{\mu_{gw}} \dfrac{\bar{k}_{rgw}}{\bar{k}_{rgd}}} = \frac{1 - G}{1 + \dfrac{\mu_{gd}}{\mu_{gw}} \dfrac{\bar{k}_{rgw}}{\bar{k}_{rgd}}}$$

  - Generally G can be neglected in the case of dry gas recycling
  - Recovery:

$$G_{pD} = \frac{\bar{S}_{gde} + (1 - \bar{f}_{gde}) G_{id}}{1 - S_{wc}}$$

where G_{pD} is the cumulative recovery of wet gas (in HCPV)

and G_{iD} is the cumulative dry gas injected (in PV)

Dry gas recycling

- **Dry gas recycling aims to inject dry gas in retrograde gas condensates reservoir in order to maintain pressure**
- **The objective is**
  - to prevent the pressure to drop below dew point
  - to prevent the phenomenon of condensates banking in the vicinity of the wells and to improve recovery of condensates
- **Despite being a miscible process, the immiscible approach is still valid for dry gas recycling using black-oil model**
- **Using averaged pseudo relative permeabilities and fractional flow makes the flow one-dimensional and allows to use Buckley-Leverett theory and Welge tangent method in order to forecast recovery**
- **The final performance strongly depends on the vertical distribution of the permeabilities in the reservoir**
- **The driving parameter is the liquid yield r_s and the corresponding economics**